# Prevention of Significant Air Quality Deterioration Review

## Preliminary Determination

September 10, 2021

Facility Name: Washington County Power, LLC
City: Sandersville
County: Washington
AIRS Number: 04-13-30300039
Application Number: TV-547905
Date Application Received: February 25, 2021

Review Conducted by:
State of Georgia - Department of Natural Resources
Environmental Protection Division - Air Protection Branch
Stationary Source Permitting Program

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## SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Washington County Power, LLC for a permit to retrofit four existing natural gas-fired simple cycle combustion turbines with fuel oil combustion capabilities. The proposed project will include the construction of a 2.5 million gallon vertical fixed-roof fuel oil storage tank, with a conservatively estimated fuel oil throughput of 30 million gallons per year. WCP will also install and operate a water-injection system to be used during fuel oil combustion. Auxiliary equipment includes pump skids, tanks, and a raw-water storage tank for water injection control. The facility is requesting with the proposed modification an operational limit for the combustion turbines of 12,000 total hours per year while firing natural gas and 2,000 total hours per year while firing fuel oil.

The proposed project will result in an increase in emissions from the facility. The sources of these increases in emissions include the modified four simple cycle combustion turbines, the fuel oil storage tank and associated emission units (two 10.1 MMBtu/hr natural gas-fired fuel preheaters).

The modification of the Washington County Power, LLC facility due to this project will result in an emissions increase in particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns and smaller ($PM_{10}$), particulate matter with an aerodynamic diameter of 2.5 microns and smaller ($PM_{2.5}$), sulfur dioxide ($SO_2$), nitrogen oxides (NOx), volatile organic compounds (VOC), carbon monoxide (CO), and greenhouse gases (GHG) in terms of carbon dioxide equivalents ($CO_2e$), lead (Pb), and sulfuric acid mist ($H_2SO_4$). A Prevention of Significant Deterioration (PSD) analysis was performed for the facility for all pollutants to determine if any increase was above the "significance" level. The PM, $PM_{10}$, $PM_{2.5}$, NOx, VOC, CO, and GHG in terms of $CO_2e$ emissions increases were above the PSD significant level thresholds.

The Washington County Power, LLC is located in Washington County, which is classified as "attainment" or "unclassifiable" for $SO_2$, $PM_{2.5}$ and $PM_{10}$, $NO_X$, CO, and ozone (VOC).

The EPD review of the data submitted by Washington County Power, LLC related to the proposed modifications indicates that the project will comply with all applicable state and federal air quality regulations.

It is the preliminary determination of the EPD that the proposal provides for the application of Best Available Control Technology (BACT) for the control of PM, $PM_{10}$, $PM_{2.5}$, NOx, VOC, CO, and GHG in terms of $CO_2e$ as required by federal PSD regulation 40 CFR 52.21(j).

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility or in Class I areas located within 200 km of the facility.

It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Washington County Power, LLC for the modifications necessary to retrofit four natural gas-fired simple cycle combustion turbines with fuel oil combustion capabilities. Various conditions have

been incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A. This Preliminary Determination also acts as a narrative for the Title V Permit.

## 1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On February 25, 2021, Washington County Power, LLC (hereafter referred to as "WCP") submitted an application for an air quality permit to retrofit four simple cycle combustion turbines to fire natural gas or fuel oil. The facility is located at 1177 County Line Road in Sandersville, Washington County.

**Table 1-1: Title V Major Source Status**

| Pollutant | Is the Pollutant Emitted? | If emitted, what is the facility's Title V status for the Pollutant? | | |
|---|---|---|---|---|
| | | Major Source Status | Major Source Requesting SM Status | Non-Major Source Status |
| PM | Y | ✓ | | |
| $PM_{10}$ | Y | ✓ | | |
| $PM_{2.5}$ | Y | ✓ | | |
| $SO_2$ | Y | | | ✓ |
| VOC | Y | ✓ | | |
| $NO_x$ | Y | ✓ | | |
| CO | Y | ✓ | | |
| TRS | N/A | | | |
| $H_2S$ | N/A | | | |
| Individual HAP | Y | | | ✓ |
| Total HAPs | Y | | | ✓ |
| Total GHGs | Y | ✓ | | |

Table 1-2 below lists all current Title V permits, all amendments, 502(b)(10) changes, and off-permit changes, issued to the facility, based on a review of the "Permit" file(s) on the facility found in the Air Branch office.

**Table 1-2: List of Current Permits, Amendments, and Off-Permit Changes**

| Permit Number and/or Off-Permit Change | Date of Issuance/ Effectiveness | Purpose of Issuance |
|---|---|---|
| 4911-303-0039-V-08-1 | January 11, 2021 | Title V Renewal |

Based on the proposed project description and data provided in the permit application, the estimated incremental increases of regulated pollutants from the facility are listed in Table 1-3 below:

**Table 1-3: Emissions Increases from the Project**

| Pollutant | Baseline Years | Net Emissions Increase (tpy) | PSD Significant Emission Rate (tpy) | Subject to PSD Review |
|---|---|---|---|---|
| PM | August 2011 – July 2013 | 97.11 | 25 | Yes |
| $PM_{10}$ | August 2011 – July 2013 | 154.76 | 15 | Yes |
| $PM_{2.5}$ | August 2011 – July 2013 | 154.76 | 10 | Yes |
| VOC | August 2011 – July 2013 | 95.21 | 40 | Yes |
| $NO_X$ | August 2011 – July 2013 | 565.97 | 40 | Yes |

| Pollutant | Baseline Years | Net Emissions Increase (tpy) | PSD Significant Emission Rate (tpy) | Subject to PSD Review |
|---|---|---|---|---|
| CO | August 2011 – July 2013 | 264.21 | 100 | Yes |
| $SO_2$ | August 2011 – July 2013 | 8.86 | 40 | No |
| $H_2SO_4$ | August 2011 – July 2013 | 4.5 | 7 | No |
| $CO_2e$ (Greenhouse Gases) | August 2011 – July 2013 | 1,402,932 | 75,000 | Yes |
| Pb | August 2011 – July 2013 | 0.03 | 0.6 | No |

The definition of baseline actual emissions for existing emission units is the average emission rate, in tons per year, at which the emission unit actually emitted the pollutant during any consecutive 24-month period selected by the facility within the 10-year period immediately proceeding the date a complete permit application was received by EPD. The facility chose a baseline period of August 2011 through July 2013 for $SO_2$, PM, $PM_{10}$, $PM_{2.5}$, NOx, VOC, CO, $CO_2e$, and $H_2SO_4$. The net increases were calculated by subtracting the baseline actual emissions from the future project potential emissions of the combustion turbines, fuel oil tank, and associated emission increases from non-modified equipment. Table 1-4 details this emissions summary. The emissions calculations for Tables 1-3 and 1-4 can be found in detail in the facility's PSD application [see Appendix B (revised April 23, 2021) of Volume I of Application No. TV-547905]. These calculations have been reviewed and approved by the Division.

Baseline Combustion Turbines:

Historically monitored monthly emission totals of NOx, $SO_2$ and $CO_2$ and historically monitored monthly heat inputs and emission factors are used to calculate the baseline actual emissions. Actual CEMs data from August 2011 through July 2013 were used to calculated baseline NOx and $CO_2$ emissions. Baseline emissions of $CO_2e$ are calculated using the historical $CO_2$ emission data, AP-42 Chapter 3.1, Table 3.1-2a emission factors for $CH_4$ and $N_2O$, global warming potentials for $CH_4$ and $N_2O$ from 40 CFR 98, Subpart A, Table A-1, and actual heat input data from August 2011 through July 2013. PM Filterable, Condensable PM, Total PM, $PM_{10}$, $PM_{2.5}$, CO, VOC, and $H_2SO_4$ are calculated using emission factors and actual heat input data from August 2011 through July 2013. Historical data can be found in Tables B-1 and B-2 and emission factors for natural gas combustion are given in Table B-3 of Appendix B of Volume I of Application No. TV-547905.

Project Potential-to-Emit:

Combustion Turbines:

Project potential-to-emit is determined on a pollutant-by-pollutant basis and based on a maximum annual operation of 12,000 hours of natural gas-firing and 2,000 hours of fuel oil-firing for the combustion turbines. Potential-to-emit also includes annual tons per year emission estimates for NOx, CO, and VOC considering and inclusive of startup/shutdown activities at the facility. Three-hundred hours per year on natural gas and 50 hours per year on fuel oil per turbine or assuming approximately 10% of estimated operating time allocated for startup/shutdown.

Startup/shutdown emission factors are based on review and engineering analysis of existing source operational data for startup/shutdown activities. The emission factors used for startup/shutdown on Natural gas are 0.05 lbs/MMBtu for NOx, 0.03 lbs/MMBtu for CO and 0.01 lbs/MMBtu for

VOC, and on fuel oil: 0.25 lbs/MMBtu for NOx, 0.07 lbs/MMBtu for CO and 0.03 lbs/MMBtu for VOC. Emission factors for NOx, CO and VOC during normal operation are the proposed BACT: Natural Gas – 9.0 ppm (0.030 lbs/MMBtu) for NOx, 9.0 ppm (0.0182 lbs/MMBtu) for CO, 2.0 ppm (0.00637 lbs/MMBtu) for VOC, and Fuel Oil – 42 ppm (0.14 lbs/MMBtu) for NOx, 20 ppm (0.0405 lbs/MMBtu) for CO, 5.0 ppm (0.0159 lbs/MMBtu) for VOC. These calculations are based on a heat input of 1,766 MMBtu/hr on natural gas and 1,890 MMBtu/hr on fuel oil. $SO_2$ and $H_2SO_4$ emission factors are based on the combustion of ultra-low sulfur diesel. Equivalent to BACT limit for Total PM/PM10/PM2.5 was used for the emission factor of 0.0137 lbs/MMBtu for natural gas and 0.0142 lbs/MMBtu for fuel oil.

GHG emissions from the combustion of natural gas and fuel oil are calculated based on the emission factors for $CO_2$, $CH_4$, and $N_2O$ listed in 40 CFR 98 Subpart C, Tables C-1 and C-2. Total GHG in terms of CO2e is calculated by multiplying each individual GHG emitted by its respective global warming potential for Table1 to 40 CFR 98 Subpart A.

Fuel Oil Storage Tank:

In addition, a new fuel oil storage tank is being proposed for installation. The fuel oil storage tank will have a capacity of 2.5 milling gallons and is assumed to operate continuously at 8,760 hours per year. It was conservatively assumed that the tank will experience one turnover of fuel oil per month for a total fuel oil throughput of 30 million gallons per year. Emissions from the storage tank are estimated using the latest version of Trinity's TankESP Software (based on AP-42 Chapter 7 for VOC emissions from storage tanks).

Two Natural Gas Preheaters:

Two 10.1 MMBtu/hr natural gas preheaters are anticipated to experience associated emissions increases due to additional hours of potential annual operation resulting from the proposed project. Based on the proposed 3,000 hours of annual natural gas combustion per turbine, an estimated operational increase of 5,088 hours per year for each natural gas preheater. Emissions of Total PM/$PM_{10}$/$PM_{2.5}$, NOx CO, VOC, and lead are calculated using emission factors from AP-42 Section 1.4, Natural Gas Combustion, Table 1.4-1 and 2. Emissions of $SO_2$ and $H_2SO_4$ are estimated based on a natural gas sulfur content of 0.05 grains per 100 standard cubic feet and 100% conversion of fuel sulfur to $SO_2$ and a 15% oxidation rate of $H_2SO_4$.

GHG emissions from the combustion of natural gas are calculated based on the emission factors for $CO_2$, $CH_4$, and $N_2O$ listed in 40 CFR 98 Subpart C, Tables C-1 and C-2. Total GHG in terms of CO2e is calculated by multiplying each individual GHG emitted by its respective global warming potential for Table1 to 40 CFR 98 Subpart A.

<u>Emission Factors:</u>

Emission factors for natural gas combustion are obtained from the emission limitations in the currently effective Major Source Operating Permit No. 301-0073 for the Calhoun Energy Center (a similar facility) located in Eastaboga, Alabama, and AP-42 Chapter 3.1 Stationary Gas Turbines, Table 3.1-2a (Total PM/$PM_{10}$/$PM_{2.5}$). $SO_2$ factor is the default emission rate for pipeline natural gas from 40 CFR 75, Appendix D, Section 2.3.1.12. Emissions of $PM_{10}$ and $PM_{2.5}$ are assumed to be equivalent to emissions of total PM. $CO_2$ emission factor based on EPA default factors in 40

CFR Part 98 Subpart C Tables C-1 and C-2, effective January 1, 2014, for Natural Gas. The $CO_2e$ factor is calculated based on the emission factors for $CO_2$, $CH_4$, and $N_2O$ and the global warming potential (GWP) for each pollutant per 40 CFR 98, Subpart A, Table A-1. For firing of fuel oil, $SO_2$ and $H_2SO_4$ emission factors are based on the combustion of ultra-low sulfur diesel, and Total PM/$PM_{10}$/$PM_{2.5}$ based on site-specific data and proposed BACT limit. Emission factor for filterable PM is the delta between the Total PM and Condensable PM emission factors. $CO_2$ emission factor based on EPA default factors in 40 CFR Part 98 Subpart C Tables C-1 and C-2, effective January 1, 2014, for Petroleum Products/Distillate Fuel Oil No. 2. The $CO_2e$ factor is calculated based on the emission factors for $CO_2$, $CH_4$, and $N_2O$ and the global warming potential (GWP) for each pollutant per 40 CFR 98, Subpart A, Table A-1. The emission factors are given in Tables B-3 and B-4 of Appendix B of Volume I of Application No. TV-547905.

**Table 1-4: Net Change in Emissions Due to the Major PSD Modification**

| Pollutant | Modified and New Units | | Associated Units Emissions Increase (tpy) | Total Emission Increases (tpy) | PSD Significant Emission Rate (tpy) |
|---|---|---|---|---|---|
| | Baseline Actual Emissions (tpy) | Future Potential Emissions (tpy) | | | |
| PM | 11.58 | 108.59 | 0.10 | 97.11 | 25 |
| $PM_{10}$ | 17.63 | 172.00 | 0.38 | 154.76 | 15 |
| $PM_{2.5}$ | 17.63 | 172.00 | 0.38 | 154.76 | 10 |
| VOC | 8.19 | 103.11 | 0.28 | 95.21 | 40 |
| $NO_X$ | 50.00 | 610.94 | 5.04 | 565.97 | 40 |
| CO | 23.46 | 283.44 | 4.23 | 264.21 | 100 |
| $SO_2$ | 0.40 | 9.19 | 0.07 | 8.86 | 40 |
| $H_2SO_4$ | 0.51 | 4.99 | 0.02 | 4.5 | 7 |
| Pb | - | 0.03 | 2.52e-5 | 0.03 | 0.60 |
| $CO_2e$ | 153,070 | 1,549,985 | 6,017 | 1,402,932 | 75,000 |

Based on the information presented in Tables 1-3 and 1-4 above, WCP's proposed modification, as specified per Georgia Air Quality Application No. TV-547905, is classified as a major modification under PSD because the potential emissions of Total PM, $PM_{10}$, $PM_{2.5}$, VOC, NOx, CO and $CO_2e$ exceed the PSD Significant Emission Rates.

Through its new source review procedure, EPD has evaluated WCP's proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination.

## 2.0 PROCESS DESCRIPTION

According to Application No. TV-547905, WCP is proposing the addition of fuel oil combustion capability for all existing facility turbines to enhance fuel resiliency given increased reliance within the utilities and industrial sectors on natural gas for energy generation. This project requires physical modifications to each of the four turbines and installation of fuel oil storage capacity. WCP is requesting permit conditions limiting natural gas firing from the group of four turbines to 12,000 hours per year (hrs/yr) and fuel oil combustion to 2,000 hrs/yr. The proposed fuel oil storage capacity on-site could be as much as a 2.5 million gallon vertical fixed-roof storage tank, with a conservatively estimated fuel oil throughput of 30 million gallons per year. WCP proposes to continue operating the existing Dry Low NOx burners on the turbines during gas combustion and proposes to install and operate a water-injection system during fuel oil combustion. As the units are large-frame simple-cycle units, startup and shutdown operations will generally be limited to less than 30 minutes for both gas and oil operations. Therefore, worst-case hourly conditions for these turbines is generally considered to be a full hour at 100% operating load (steady-state). During gas combustion at 100% operating load, the estimated heat input capacity is estimated to be 1,766 Million British Thermal Units per hour (MMBtu/hr) for each turbine, whereas during fuel oil combustion at 100% operating load, the heat input capacity is estimated to be 1,890 MMBtu/hr for each turbine. Collectively, the four turbines will continue to maintain a 680-MW capacity for the site. WCP does not plan to expand overall short-term generating capacity. However, the annual generation (MW-hr) may increase due to both the addition of fuel oil operating capacity and additional run-time capacity on natural gas. This project would also require WCP to add pump skids, tanks, and a raw water storage tank for the purposes of water injection control but should not require the addition or modification of any other emission units on-site.

The WCP permit application and supporting documentation are included in Appendix A of this Preliminary Determination and can be found online at [https://epd.georgia.gov/psd112gnaa-nsrpcp-permits-database](https://epd.georgia.gov/psd112gnaa-nsrpcp-permits-database).

## 3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

### State Rules

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1) requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Georgia Rule 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

Georgia Rule 391-3-1-.02(2)(b) – Visible Emissions
Rule (b) limits the visible emissions from any emissions source not subject to some other visible emissions limitation under GRAQC 391-3-1-.02 to 40% opacity. Visible emissions testing may be required at the discretion of the Director.

The combustion turbines at WCP are subject to this regulation. The turbines presently fire pipeline-quality natural gas with emissions exhibiting minimal opacity. As the turbines will be modified to combust ULSD fuel oil, it is anticipated that the firing of these relatively clean fuels in conjunction with proper operation ensures compliance with this rule. No applicable requirements per Rule (b) will be altered as a result of the proposed project.

Georgia Rule 391-3-1-.02(2)(d) – Fuel-Burning Equipment
Rule (d) limits the PM emissions, visible emissions, and NOx emissions from fuel-burning equipment. The standards are applied based on installation date, the heat input capacity of the unit, and the fuel(s) combusted. The GRAQC defines "fuel-burning equipment" as follows:

> *"Fuel-burning equipment" means equipment the primary purpose of which is the production of thermal energy from the combustion of any fuel. Such equipment is generally that used for, but not limited to, heating water, generating or super heating steam, heating air as in warm air furnaces, furnishing process heat indirectly, through transfer by fluids or transmissions through process vessel walls."*

The combustion turbines are used for the generation of electric power, not the production of thermal energy. Therefore, they do not meet the definition of fuel burning equipment and are not subject to the requirements of Rule (d).

Georgia Rule 391-3-1-.02(2)(e) – Particulate Emissions from Manufacturing Processes
Rule (e) establishes PM limits where not elsewhere specified. Combustion turbines are not technically subject to a separate particulate limit rule, and historically have not been regulated by Rule (e). Therefore, the combustion turbines at WCP are not subject to this regulation.

Georgia Rule 391-3-1-.02(2)(g), Sulfur Dioxide

Rule (g) limits the maximum sulfur content of any fuel combusted in a fuel-burning source, based on the heat input capacity. As this rule applies to all “fuel-burning sources” and not just “fuel-burning equipment” this rule applies to the combustion turbines (Source Codes: T1-T4). Rule 391-3-1-.02(2)(g)1 applies to each combustion turbine because each has an individual heat input capacity exceeding 250 MMBtu/hr and was constructed after January 1, 1972. Sulfur dioxide emissions from each combustion turbine shall not exceed 0.8 lb/MMBtu of heat input derived from liquid fossil fuel in accordance with Rule 391-3-1-.02(2)(g)1(i). The fuel sulfur content limit for fuels burned in each combustion turbine is 3 percent sulfur by weight in accordance with Rule 391-3-1-.02(2)(g)2, which applies to each piece of equipment rated at 100 MMBtu/hr or greater regardless of fuel type. The proposed permit will require that the facility only fire distillate fuel oil with a 0.0015% sulfur content and natural gas, thus limiting fuel sulfur content to well below 3% sulfur. This limit is subsumed by the more stringent fuel sulfur limit under NSPS Subpart KKKK.

Georgia Rule 391-3-1-.02(2)(n) – Fugitive Dust

Rule (n) requires facilities to take reasonable precautions to prevent fugitive dust from becoming airborne. WCP will continue to take the appropriate precautions to prevent fugitive dust from becoming airborne for any applicable equipment.

Georgia Rule 391-3-1-.02(2)(bb) – Petroleum Liquid Storage

Rule (bb) establishes requirements for storage tanks with a capacity greater than 40,000 gallons storing a petroleum liquid with a true vapor pressure greater than 1.52 pounds per square inch absolute (psia). As the ULSD has a true vapor pressure less than 1.52 psia, the new fuel oil storage tank is not subject to the requirements of Rule (bb).

Georgia Rule 391-3-1-.02(2)(nn) – VOC Emissions from External Floating Roof Tanks

Rule (nn) establishes requirements for external floating roof tanks storing petroleum liquids with a capacity greater than 40,000 gallons. As the proposed fuel oil storage tank is a fixed roof tank and not an external floating roof tank, Rule (nn) will not apply.

Georgia Rule 391-3-1-.02(2)(tt) – VOC Emissions from Major Sources

Rule (tt) limits VOC emissions from facilities that are located in or near the original Atlanta ozone nonattainment area. WCP is not located within the geographic area covered by this rule and is, therefore, not subject to this regulation.

Georgia Rule 391-3-1-.02(2)(uu) – Visibility Protection

Rule (uu) requires EPD to provide an analysis of a proposed major source or a major modification to an existing source’s anticipated impact on visibility in any federal Class I area to the appropriate Federal Land Manager (FLM). The visibility-impacting pollutants include NOx, $PM_{10}$, $SO_2$, and $H_2SO_4$. A screening analysis of federal Class I areas resulted in a Q/d value less than 10. Therefore, a full review of the anticipated impact on visibility was not performed. Further documentation regarding an evaluation of impacts related to these projects on Class I areas, and further documentation referenced such as correspondence with the appropriate FLM, is provided in Volume II of Application No. TV-547905.

The following Georgia State rules are not applicable since WCP (which is located in Washington County) is not located within the geographic area covered by these rules.

- Volatile Organic Liquid Handling and Storage - GRAQC 391-3-1-.02(2)(vv)
- Nitrogen Oxides from Major Sources - GRAQC 391-3-1-.02(2)(yy)
- $NO_X$ from Electric Utility Steam Generating Units - GRAQC 391-3-1-.02(2)(jjj)
- $NO_X$ from Fuel-Burning Equipment - GRAQC 391-3-1-.02(2)(lll)
- $NO_X$ Emissions from Stationary Gas Turbines and Stationary Engines used to Generate Electricity - GRAQC 391-3-1-.02(2)(mmm)
- $NO_X$ Emissions from Large Stationary Gas Turbines - GRAQC 391-3-1-.02(2)(nnn)
- $NO_X$ from Small Fuel-Burning Equipment - GRAQC 391-3-1-.02(2)(rrr)

The following Georgia State rules are not applicable since none of the units at WCP are listed in the regulation.

- Multipollutant Control for Electric Utility Steam Generating Units - GRAQC 391-3-1-.02(2)(sss)
- SO2 Emissions from Electric Utility Steam Generating Units - GRAQC 391-3-1-.02(2)(uuu)

Georgia Rules 391-3-1-.02(12), (13), and (14) – Cross State Air Pollution Rules (Annual $NO_X$, Annual $SO_2$, and Ozone Season $NO_X$)

These regulations incorporate the Cross State Air Pollution Rule (CSAPR) requirements into the Georgia Rules for Air Quality Control. The regulations provide allocations for Georgia for 2017 and thereafter.

Georgia Rule 391-3-1-.03(1) – Construction (SIP) Permitting

The proposed projects will require physical construction activities to complete the proposed modifications. Potential emissions associated with the proposed projects are above the de minimis construction permitting thresholds specified in GRAQC 391-3-1-.03(6)(i). Further, as discussed in Section 4.1 of Volume I of the Application, PSD permitting is required for multiple pollutants. Therefore, a construction permit application is necessary, and the appropriate forms are included in Appendix D of Volume I of the Application.

## Federal Rule - PSD

The regulations for PSD in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply to any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or to all other sources having potential emissions of 250 tons per year or more of any regulated pollutant. They also apply to any modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

Georgia has adopted a regulatory program for PSD permits, which the United States Environmental Protection Agency (EPA) has approved as part of Georgia's State Implementation Plan (SIP). This regulatory program is located in the Georgia Rules at 391-3-1-.02(7). This means that Georgia EPD issues PSD permits for new major sources pursuant to the requirements of Georgia's regulations. It also means that Georgia EPD considers, but is not legally bound to accept, EPA comments or guidance. A commonly used source of EPA guidance on PSD permitting is EPA's Draft October 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting (NSR Workshop Manual). The NSR Workshop Manual is a comprehensive guidance document on the entire PSD permitting process.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of BACT for each regulated pollutant that would be emitted in significant amounts;
- Analysis of the ambient air impact;
- Analysis of the impact on soils, vegetation, and visibility;
- Analysis of the impact on Class I areas; and
- Public notification of the proposed plant in a newspaper of general circulation

## Definition of BACT

The PSD regulation requires that BACT be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case, EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS). In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose and enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

EPA's NSR Workshop Manual includes guidance on the 5-step top-down process for determining BACT. In general, Georgia EPD requires PSD permit applicants to use the top-down process in the BACT analysis, which EPA reviews. The five steps of a top-down BACT review procedure identified by EPA per BACT guidelines are listed below:

Step 1: Identification of all control technologies;
Step 2: Elimination of technically infeasible options;
Step 3: Ranking of remaining control technologies by control effectiveness;
Step 4: Evaluation of the most effective controls and documentation of results; and
Step 5: Selection of BACT.

The following is a discussion of the applicable federal rules and regulations pertaining to the equipment that is the subject of this preliminary determination, which is then followed by the top-down BACT analysis.

## New Source Performance Standards

The federal NSPS regulations are codified at 40 CFR Part 60. NSPS apply to new or modified "affected facilities" as defined in specific subparts of 40 CFR Part 60. Georgia EPD has been delegated the authority to administer the federal NSPS and has adopted by reference, unless otherwise noted, the NSPS standards. *See* Air Quality Control Rule 391-3-1- 02(8). Additional discussion of NSPS applicability is presented below.

40 CFR Part 60, Subpart A – General Provisions

Subpart A contains the general provisions of the NSPS regulations. Specifically, the provisions of Subpart A apply to the owner or operator of any stationary source that contains an affected facility, construction or modification of which is commenced after the date of publication of the standard and is subject to any standard, limitation, prohibition, or other federally enforceable requirement established pursuant to Part 60. General requirements may include notifications, monitoring, recordkeeping and/or performance testing of specific sources.

40 CFR Part 60, Subpart Kb – Volatile Organic Liquid Storage Vessels (Including Petroleum Liquids Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

The requirements of NSPS Subpart Kb apply to storage vessels which have a storage capacity greater than 19,813 gallons that store Volatile Organic Liquids (VOL) for which construction, modification, or reconstruction commenced after July 23, 1984. However, per 40 CFR 60.110b(b), NSPS Kb does not apply to storage vessels with a storage capacity greater than 39,890 gallons storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa). The proposed fuel oil storage tank at the facility will have a storage capacity of 2.5 million gallons and will store ultra-low sulfur diesel (ULSD). The maximum true vapor pressure of the ULSD stored in the fuel oil storage tank is far less than the 3.5 kPa threshold; therefore, the requirements of NSPS Kb do not apply.

40 CFR Part 60, Subpart GG – Stationary Gas Turbines

NSPS Subpart GG, Standards of Performance for Stationary Gas Turbines, applies to all stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, that are constructed, modified, or reconstructed after October 3, 1977.

Presently, the combustion turbines are subject to NSPS Subpart GG. However, upon completion of the proposed modifications, the combustion turbines will be subject to the more recently promulgated standards for Stationary Combustion Turbines under NSPS 40 CFR Part 60, Subpart KKKK. Pursuant to 40 CFR 60.4305(b) (NSPS Subpart KKKK), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. Therefore, NSPS Subpart GG will no longer apply to the WCP combustion turbines following the proposed project.

40 CFR Part 60, Subpart KKKK – Stationary Combustion Turbines

NSPS Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, applies to all stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired, and were constructed, reconstructed, or modified after February 2005. The Facility presently operates four natural gas-fired simple-cycle combustion turbines, each with a heat input capacity exceeding 10 MMBtu/hr. Following the proposed project, the turbines will also be able to combust fuel oil. To determine if the turbines will be subject to NSPS Subpart KKKK following the proposed project, it is necessary to ascertain if a "modification" per the NSPS has occurred. For purposes of NSPS, a modification is defined as[1]

> *"…any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted."*

NSPS Subpart KKKK establishes standards for NOx and $SO_2$. As the combustion of fuel oil will result in the increase of both pollutants when compared to natural gas combustion, the proposed project qualifies as an NSPS modification, resulting in the Facility's combustion turbines being subject to the requirements of NSPS Subpart KKKK. Per 40 CFR 60.4305(b), stationary combustion turbines regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subpart GG. Therefore, the existing NSPS Subpart GG requirements will no longer apply. The NSPS Subpart KKKK requirements will replace the NSPS Subpart GG requirements established per Conditions 3.3.1, 3.3.3 and 3.3.4 of the existing Title V operating permit. The following sections detail the applicable requirements as a result of NSPS Subpart KKKK applicability.

[1] 40 CFR 60.2

Emission Limits

Per Table 1 to Subpart KKKK, a modified combustion turbine is limited to NOx emission limits depending on the type of fuel combusted and the heat input at peak load. For modified combustion turbines firing natural gas with a rating greater than 850 MMBtu/hr, the NOx emission standard is 15 ppm at 15% $O_2$ or 0.43 lb/MWh useful output. Additionally, for modified combustion turbines firing fuels other than natural gas with a rating greater than 850 MMBtu/hr, the NOx emission standard is 42 ppm at 15% $O_2$ or 1.3 lb/MWh useful output. Subpart KKKK also includes, for units greater than 30 MW output, a NOx limit of 96 ppm at 15% $O_2$ or 4.7 lb/MWh useful output for turbine operation at ambient temperatures less than 0°F and turbine operation at loads less than 75% of peak load. Compliance with the NOx emission limit is determined on a 4-hour rolling average basis. $SO_2$ emissions from combustion turbines located in the continental U.S. are limited to 0.9 lb/MWh gross output (or 110 ng/J), or the units must not burn any fuel with total potential sulfur emissions in excess of 0.060 lb $SO_2$/MMBtu heat input (or 26 ng $SO_2$/J).

Monitoring and Testing Requirements

Pursuant to 40 CFR 60.4333(a), the combustion turbines, air pollution control equipment, and monitoring equipment will be maintained in a manner that is consistent with good air pollution control practices for minimizing emissions. This requirement applies at all times including during startup, shutdown, and malfunction.

NOx Compliance Demonstration Requirements

The combustion turbine systems currently employ a continuous emission monitoring system (CEMS) for NOx per the requirements of the Acid Rain Program (ARP), promulgated in 40 CFR Part 75. Per 40 CFR 4340(b)(2)(iv), units operating without water injection that are regulated by 40 CFR Part 75 may rely on the 40 CFR Part 75 Appendix E procedures for documenting ongoing compliance with the NSPS Subpart KKKK NOx standards with approval from the state. The WCP units operate without water injection during natural gas combustion.

Water injection will be required for fuel oil combustion. 40 CFR 60.4335 establishes NOx monitoring options for water injection, including use of a CEM, but does not explicitly state that the Part 75 procedures may be relied upon. However, NSPS Subpart KKKK specific requirements for a CEM are detailed in 40 CFR 60.4345, including an option to rely on a CEM installed and certified per 40 CFR Part 75.32 Therefore, the use of the existing NOx CEMs meeting the requirements of 40 CFR Part 75 Appendix E should be sufficient for NSPS Subpart KKKK NOx ongoing compliance monitoring purposes.

Sources demonstrating compliance with the NOx emission limits via CEMS are not subject to the requirement to perform initial and annual NOx stack tests.[2] Initial compliance with the applicable NOx emission limits will be demonstrated by comparing the arithmetic average of the NOx emissions measurements taken during the initial RATA to the NOx emission limit under this subpart.[3]

[2] 40 CFR 60.4340(b), 40 CFR 60.4405

[3] 40 CFR 60.4405(c) and (d)

$SO_2$ Compliance Demonstration Requirements

For compliance with the $SO_2$ emission limit, facilities are required to perform regular determinations of the total sulfur content of the combustion fuel and to conduct initial and annual compliance demonstrations. The total sulfur content of gaseous fuel combusted in the combustion turbine must be determined and recorded once per operating day or using a custom schedule as approved by EPD.[4] The total sulfur content of fuel oil combusted in the combustion turbine must be determined by flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank.[5]

However, as allowed per 40 CFR 60.4365, WCP elects to opt out of these provisions of the rule by using natural gas and fuel oil which are demonstrated not to exceed potential sulfur emissions of 0.060 lb/MMBtu $SO_2$. This demonstration can be made using one of the following methods:

1. By using valid purchase contracts, tariff sheets, or transportation contracts for the fuel, specifying that the fuel sulfur content for the natural gas is less than or equal to 20 grains of sulfur per 100 standard cubic feet and/or that the maximum total sulfur content for fuel oil is 0.05 weight percent (500 ppmw) or less. These limitations will serve as demonstration that potential emissions will not exceed 0.060 lb/MMBtu.

2. By using representative fuel sampling data meeting the requirements of 40 CFR 75, Appendix D, Sections 2.3.1.4 or 2.3.2.4 which show that the sulfur content of the fuel does not exceed 0.060 lb $SO_2$/MMBtu heat input.

WCP is currently required to monitor the sulfur content of the natural gas burned in the combustion turbines through submittal of a semiannual analysis of the gas by the supplier or a current, valid purchase contract, tariff sheet, or transportation contract for the gaseous fuel, specifying that the maximum sulfur content does not exceed its excursion threshold of 20.0 grains per 100 standard cubic feet.[6] This sulfur content analysis by the supplier satisfies the sulfur content demonstration methodologies for natural gas in 40 CFR 60.4365(a) and (b), respectively. Therefore, continued compliance with this existing permit condition will guarantee compliance with these NSPS KKKK requirements for natural gas combustion.

As a result of this proposed project, all four combustion turbines at the facility will be retrofitted to allow for the combustion of fuel oil. Therefore, in accordance with 40 CFR 60.6365(a) and (b), WCP will now be required to monitor the sulfur content of the fuel oil burned in the combustion turbines through the submittal of a semiannual analysis of the fuel oil by the supplier or a current, valid purchase contract, tariff sheet, or transportation contract for the fuel oil, specifying that the maximum total sulfur content is 0.05 weight percent (500 ppmw) or less.

[4] 40 CFR 60.4370(b) and (c)

[5] 40 CFR 60.4370(a), procedures and frequencies per 40 CFR 75, Appendix D, Sections 2.2.3, 2.2.4.1, 2.2.4.2, or 2.2.4.3

[6] Permit No. 4911-303-0039-V-08-0, Condition 6.2.8

Initial Notification

Per 40 CFR 60.7(a)(4), Application No. TV-547905 serves as the required notification for any physical or operational change to an existing facility which qualifies as an NSPS modification.

40 CFR 60 Subpart TTTT – Greenhouse Gas Emissions for Electric Generating Units

NSPS Subpart TTTT, Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units applies to any fossil fuel fired steam generating unit, Integrated Gasification Combined Cycle (IGCC) unit, or stationary combustion turbine constructed after January 8, 2014 or reconstructed after June 8, 2014 and to any steam generating unit or IGCC modified after June 8, 2014, provided that unit has a base load rating greater than 250 MMBtu/hr and serves a generator capable of selling greater than 25 MW of electricity to the grid.[7] The existing simple cycle combustion turbines at the WCP each have peak heat inputs greater than 250 MMBtu/hr and serve a generator greater than 25 MW. Therefore, these stationary combustion turbines could potentially be subject to the provisions of NSPS TTTT.

With respect to stationary combustion turbines, NSPS Subpart TTTT applies only to units that commenced construction or reconstruction after June 18, 2014, not modification. "Reconstruction" is defined as the replacement of components of an existing affected facility such that the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable, entirely new affected facility that is technologically and economically capable of complying with the applicable standards. The retrofit cost of the proposed project per turbine is $18.5 million. In comparison, the cost of a comparable, entirely new "stationary combustion turbine" capable of combusting both natural gas and fuel oil under NSPS Subpart KKKK is approximately $83 million. Thus, the costs per turbine is far less than 50% of comparable, entirely new "stationary combustion turbines" under Subpart KKKK. As the combustion turbines at WCP are existing units and the proposed projects do not meet the reconstruction definition, the modifications to the turbine systems will not trigger applicability of NSPS Subpart TTTT requirements.

Non-Applicability of All Other NSPS

NSPS are developed for particular industrial source categories. The applicability of a particular NSPS to the proposed project can be readily ascertained based on the industrial source category covered. All other NSPS, besides Subpart A, are categorically not applicable to the proposed project.

[7] 40 CFR 60.5509(a)

## National Emissions Standards For Hazardous Air Pollutants

NESHAP, located in 40 CFR 61 and 40 CFR 63, have been promulgated for source categories that emit HAP to the atmosphere. A facility that is a major source of HAP is defined as having potential emissions of greater than 25 tpy of total HAP and/or 10 tpy of individual HAP. Facilities with a potential to emit HAP at an amount less than that which is defined as a major source are otherwise considered an area source. The NESHAP allowable emissions limits are most often established on the basis of a maximum achievable control technology (MACT) determination for the particular major source. The NESHAP apply to sources in specifically regulated industrial source categories (Clean Air Act Section 112(d)) or on a case-by -case basis (Section 112(g)) for facilities not regulated as a specific industrial source type.

The WCP Sandersville facility is presently classified as an area source of HAP emissions and will remain so following the proposed projects. The determination of applicability to NESHAP requirements for the proposed projects is detailed in the following sections. Rules that are specific to certain source categories unrelated to the proposed projects are not discussed in this regulatory review.

### 40 CFR 63 Subpart A – General Provisions

NESHAP Subpart A, *General Provisions*, contains national emission standards for HAPs defined in Section 112(b) of the Clean Air Act. All affected sources, which are subject to another NESHAP in 40 CFR 63, are subject to the general provisions of NESHAP Subpart A, unless specifically excluded by the source-specific NESHAP.

### 40 CFR 63 Subpart YYYY – Combustion Turbines

NESHAP Subpart YYYY, *NESHAP for Stationary Combustion Turbines*, establishes emission and operating limits for stationary combustion turbines located at major sources of HAP.[8] Natural gas turbines at major sources are presently only subject to initial notifications requirements. As an area source of HAP, NESHAP Subpart YYYY does not apply to operations at WCP.

### 40 CFR 63 Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters

NESHAP Subpart DDDDD, NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Major Source Boiler MACT) regulates boilers and process heaters at major sources of HAP.[9] As an area source of HAP, WCP is not subject to the Major Source Boiler MACT.

[8] 40 CFR 63.6080

[9] 40 CFR 63.7480

40 CFR 63 Subpart UUUUU – Electric Utility Steam Generating Units

NESHAP Subpart UUUUU, NESHAP for Electric Utility Steam Generating Units, applies to electric utility steam generating units (EGUs) that combust coal or oil.[10] Pursuant to 40 CFR 63.9983(a), area source stationary combustion turbines, other than IGCC units, are not subject to Subpart UUUUU. As the WCP Facility is an area source, NESHAP Subpart UUUUU will not apply.

40 CFR 63 Subpart JJJJJJ – Industrial, Commercial, and Institutional Boilers at Area Sources

NESHAP Subpart JJJJJJ, NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources (Area Source Boiler MACT) regulates boilers at area sources of HAP.[11] The simple cycle combustion turbines do not meet the boiler definition pursuant to 40 CFR 63.11237, which also excludes waste heat boilers:

> *Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of Boiler.*

Therefore, the requirements of NESHAP Subpart JJJJJJ do not apply to any equipment being modified as part of the proposed project.

Non-Applicability of All Other NESHAP

NESHAP are developed for particular industrial source categories. The applicability of a particular NESHAP to the proposed project can be readily ascertained based on the industrial source category covered. All other NESHAP are categorically not applicable to the proposed projects.

## State and Federal – Startup and Shutdown and Excess Emissions

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. Excess emissions from the combustion turbines (Source Codes: T1-T4) associated with the proposed project would most likely result from a malfunction of the associated control equipment. The facility cannot anticipate or predict malfunctions. However, the facility is required to minimize emissions during periods of startup, shutdown, and malfunction.

[10] 40 CFR 63.9980

[11] 40 CFR 63.11193

## Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring

Under 40 CFR 64, the *Compliance Assurance Monitoring* Regulations (CAM), facilities are required to prepare and submit monitoring plans for certain emission units with the Title V application. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation applies to units that use a control device to achieve compliance with an emission limit and whose pre-controlled emissions levels exceed the major source thresholds under the Title V permitting program. Although other units may potentially be subject to CAM upon renewal of the Title V operating permit, such units are not being modified under the proposed project and need not be considered for CAM applicability at this time.

The simple cycle combustion turbines at the Facility are presently not subject to CAM requirements as they do not operate control devices. Following the proposed project, each combustion turbine will operate with water injection during periods of fuel oil combustion to reduce NOx emissions. These units have a NOx CEMS to verify proper operation. Per 40 CFR 64.2(b)(1)(vi), use of a continuous compliance demonstration exempts a unit from the CAM requirements. Therefore, the turbines are not subject to CAM for NOx purposes.

## Federal Rule – 40 CFR 68 – Risk Management Plan

Subpart B of 40 CFR 68 outlines requirements for risk management prevention plans pursuant to Section 112(r) of the Clean Air Act. Applicability of the subpart is determined based on the type and quantity of chemicals stored at a facility. WCP does not exceed the threshold quantity for any of the chemicals and is, therefore, not subject to 40 CFR 68 Subpart B. WCP is and will continue to be subject to the General Duty Clause under the Clean Air Act Section 112(r)(1), which states:

> *The owners and operators of stationary sources producing, processing, handling or storing such substances [i.e., a chemical in 40 CFR part 68 or any other extremely hazardous substance] have a general duty [in the same manner and to the same extent as the general duty clause in the Occupational Safety and Health Act (OSHA)] to identify hazards which may result from (such) releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur.*

## Federal Rule – 40 CFR 72, 73, 74 – Acid Rain Program

In order to reduce acid rain in the United States and Canada, Title IV (40 CFR 72 et seq.) of the Clean Air Act Amendments of 1990 established the ARP to substantially reduce $SO_2$ and NOx emissions from electric utility plants. Affected units are specifically listed in Tables 1 and 2 of 40 CFR 73.10 under Phase I and Phase II of the program. Upon Phase III implementation, the ARP in general applies to fossil fuel-fired combustion sources that drive generators for the purposes of generating electricity for sale. The turbines at WCP are utility units subject to the ARP. The facility is subject to the requirements of 40 CFR 72 (permits), 40 CFR 73 ($SO_2$), and 40 CFR 75 (monitoring) but is not subject to the NOx provisions (40 CFR 76) of the ARP regulations because the turbines do not have the capability to burn coal.

Under 40 CFR 75 of the ARP, WCP is required to operate a NOx CEMS for each unit to monitor the NOx emission rate (lb/MMBtu) and to determine $SO_2$ and $CO_2$ mass emissions (tons) following the procedures in Appendices D and G, respectively. Further, the ARP requires the facility to possess $SO_2$ allowances for each ton of $SO_2$ emitted. The ARP also requires initial certification of the monitors within 90 days of commencement of commercial operation, quarterly reports, and an annual compliance certification. The ARP requirements are outlined in Section 7.9 and Attachment D of the Title V permit No. 4911-303-0039-V-08-0. The proposed projects should not alter any applicable requirements of ARP to the WCP operations, except for possible modifications to monitoring methods with use of fuel oil under 40 CFR Part 75. The facility will continue to maintain sufficient allowances under ARP for its operations.

## Federal Rule – 40 CFR 82 – Stratospheric Ozone Protection Regulations

The requirements originating from Title VI of the Clean Air Act, entitled *Protection of Stratospheric Ozone*, are contained in 40 CFR 82 Subparts A through E and Subparts G and H of 40 CFR 82 are not applicable to the Facility. 40 CFR 82 Subpart F, *Recycling and Emissions Reduction*, potentially applies if the facility operates, maintains, repairs, services, or disposes of appliances that utilize Class I, Class II, or non-exempt substitute refrigerants.[12] Subpart F generally requires persons completing the repairs, service, or disposal to be properly certified. It is expected that all repairs, service, and disposal of ozone depleting substances from such equipment (air conditioners, refrigerators, etc.) at the facility will be completed by a certified technician. WCP will continue to comply with 40 CFR 82 Subpart F.

## Federal Rule – 40 CFR 96 / 97 – Clean Air Interstate Rule (CAIR)/ Cross-State Air Pollution Rule (CSAPR)

The CAIR, 40 CFR 96, called for reductions in $SO_2$ and NOx by utilizing an emissions trading program. More broadly, 40 CFR 96 also includes a forerunner to CAIR, the NOx SIP Call / NOx Budget program, and the name of 40 CFR 96 (NOx Budget Trading Program for State Implementation Plans) still reflects the origins in regulating only NOx.

The CSAPR was developed to require affected states to reduce emissions from power plants that contribute to ozone and/or particulate matter emissions.[13] Initially finalized on July 6, 2011, the CSAPR was scheduled to replace the CAIR on January 1, 2012. However, on December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit (the “D.C. Circuit”) stayed CSAPR, pending a subsequent decision. On August 21, 2012, the D.C. Circuit then vacated CSAPR, remanding it back to EPA for further rulemaking, leaving CAIR in effect until a replacement rule was promulgated.[14] Upon appeal, the U.S. Supreme Court – on April 29, 2014 – upheld the CSAPR, reversing the D.C. Circuit’s decision and remanding the case back to that Court for further proceedings consistent with its April 2014 decision. Upon remand, the U.S. government filed a motion with the D.C. Circuit for a lift of the stay of CSAPR on June 26, 2014, and this motion was granted on October 23, 2014. Therefore, the CSAPR has replaced the CAIR. CSAPR Phase 1 implementation began January 1, 2015 for annual programs and May 1, 2015 for the ozone season

[12] 40 CFR 82.150

[13] http://www.epa.gov/airtransport/

[14] EME Homer City Generation, L.P. v. U.S. EPA. U.S. Court of Appeals for the District of Columbia Circuit, No. 11-1302, decided August 21, 2012.

program. Phase 2 implementation began on January 1, 2017 for annual programs and May 1, 2017 for ozone season programs.

Therefore, since CSAPR is currently effective, potential applicability is evaluated against the CSAPR Program and not CAIR. CSAPR applicability is found in 40 CFR 97.404 and definitions in 40 CFR 97.402 and implemented via Georgia EPD through GRAQC 391-3-1-.02(12) – (13). The CSAPR rule aims to improve air quality by reducing emissions from power plants that contribute to ozone and/or fine particulate pollution in other states. Georgia is subject to CSAPR programs for both fine particles ($SO_2$ and annual NOx) and ozone (ozone season NOx).[15]

CSAPR applicability is similar but distinct from ARP, with applicability criteria and definitions per 40 CFR 97.402.[16] In general, CSAPR regulates fossil-fuel-fired boilers and combustion turbines serving, on any day starting November 15, 1990 or later, an electrical generator with a nameplate capacity exceeding 25 MWe and producing power for sale. WCP's combustion turbines are affected sources under this regulation, and the proposed project will not alter the applicability of CSAPR to the facility's operations. WCP will continue to maintain sufficient allowances under CSAPR for its operations.

[15] https://www.epa.gov/airmarkets/map-states-covered-csapr

[16] CSAPR applicability and definitions are repeated in four separate subparts of 40 CFR 97, but each has identical definitions and applicability requirements. Subpart AAAAA (5A), which is for the NOX Annual program, is used in this discussion.

## 4.0 CONTROL TECHNOLOGY REVIEW

The BACT requirement applies to each new or modified emission unit from which there is an emissions increase of pollutants subject to PSD review. The proposed project will result in emissions that are significant enough to trigger PSD review for the following pollutants: filterable particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns ($PM_{10}$), particulate matter with an aerodynamic diameter of 2.5 microns ($PM_{2.5}$), NOx, VOC, CO, and greenhouse gases (GHG) in terms of carbon dioxide equivalents ($CO_2e$).

**<u>Combustion Turbines (Source Codes: T1-T4) - Background</u>**

Washington County Power (WCP) is in Sandersville in Washington County, Georgia. The present permitted facility consists of four simple cycle combustion turbine generators (Source codes: T1-T4) and supporting auxiliary equipment. WCP plans to modify the combustion turbines to have the ability to also fire fuel oil in addition to natural gas. The key elements of the proposed project include:

- Modifications to the four existing GE7FA simple-cycle combustion turbines
- New 2.5 million gallon vertical fixed-roof fuel oil storage tank with a throughput of 30 million gallons per year.
- Addition of hourly operating limits of 12,000 hours on natural gas, and 2,000 hours on fuel oil for the combustion turbines.

The proposed project will continue to have a generating capacity of 680 MW and will be dual fueled (pipeline-quality natural gas and ultra-low sulfur fuel oil).

Accordingly, a BACT analysis and detailed discussion of each pollutant subject to PSD permitting is assessed herein for the combustion turbine systems. No other units are being physically modified or constructed as part of the proposed projects.

**<u>Combustion Turbines (Source Codes: T1-T4) – NOx Emissions</u>**

<u>Applicant's Proposal</u>

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT on NOx emissions from each combustion turbine. The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits that are selected as BACT for NOx.

There are five (5) primary pathways of NOx production from turbine combustion processes: thermal NOx, prompt NOx, NOx from $N_2O$ intermediate reactions, fuel NOx, and NOx formed through reburning. The three most important mechanisms are thermal NOx, prompt NOx, and fuel NOx.[17] For natural gas-fired units, most NOx is derived from thermal NOx. Distillate oils also have low levels of fuel-bound nitrogen ($N_2$) that contribute to NOx formation.

[17] AP-42, Chapter 1, Section 4, Natural Gas Combustion, July 1998, and AP-42, Chapter 3, Section 1, Stationary Gas Turbines, April 2000.

Thermal NOx is formed mainly via the Zeldovich mechanism where the $N_2$ and oxygen ($O_2$) molecules in the combustion air react to form nitrogen monoxide (NO).[18] Most thermal NOx is formed in high temperature flame pockets downstream from the fuel injectors.[19] Temperature is the most important factor, and at combustion temperatures above 2,370°F, thermal NOx is formed readily.[20] Therefore, reducing combustion temperature is a common approach to reducing NOx emissions.

Prompt NOx, a form of thermal NOx, is formed in the proximity of the flame front as intermediate combustion products such as hydrogen cyanide (HCN), N, and NH are oxidized to form NOx.[21] The contribution of prompt NOx to overall NOx is relatively small but increases in low-NOx combustor designs. Prompt NOx formation is also largely insensitive to changes in temperature and pressure.[22]

Fuel NOx forms when fuels containing nitrogen are burned. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NOx. With excess air, the degree of fuel NOx formation is primarily a function of the nitrogen content of the fuel. Therefore, since natural gas contains little fuel bound nitrogen, fuel NOx is not a major contributor to NOx emissions from natural gas-fired combustion turbines.[23] Most distillate oils have nitrogen content less than 0.015 percent by weight, resulting in more fuel NOx generation than natural gas.[24]

In general, technology and emissions performance data could be limited to those turbines within the size range of typical simple cycle units, and specifically those sizes of turbines in operation at WCP. U.S. EPA has, in support of federal regulations such as the NSPS for combustion turbines (NSPS Subpart KKKK), reviewed the NOx emissions performance data for combustion turbines of all sizes and found differing performance data for turbines based on the size of the unit. As quoted by U.S. EPA, per 70 FR 8318 (2/18/05):

> *We identified a distinct difference in the technologies and capabilities between small and large turbines.... the smaller combustion chamber of small turbines provides inadequate space for the adequate mixing needed for very low NOx emission levels.*

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[18] U.S. EPA, Emission Standards Division, Alternative Control Techniques Document - NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007. January 1993

[19] U.S. EPA, Emission Standards Division, Alternative Control Techniques Document - NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007. January 1993.

[20] U.S. EPA, Emission Standards Division, Alternative Control Techniques Document - NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007. January 1993.

[21] U.S. EPA, Emission Standards Division, Alternative Control Techniques Document - NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007. January 1993.

[22] U.S. EPA, Emission Standards Division, Alternative Control Techniques Document - NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007. January 1993.

[23] U.S. EPA, Emission Standards Division, Alternative Control Techniques Document - NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007. January 1993.

[24] U.S. EPA, Emission Standards Division, Alternative Control Techniques Document - NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007. January 1993.

U.S. EPA finalized NSPS Subpart KKKK with a breakpoint in consideration of turbine sizes greater than 850 MMBtu/hr, between 50 MMBtu/hr and 850 MMBtu/hr, and less than 50 MMBtu/hr. Since the WCP units are above the 850 MMBtu/hr size range, only units greater than 850 MMBtu/hr are truly comparable, since as identified by U.S. EPA, there are inherent design differences in units at that size and above that can lead to inherently lower $NO_X$ emission levels. Therefore, the RBLC review was limited to units of comparable size. For conservatism, WCP focused on units of approximately 100 Megawatts (MW) in size or greater.[25]

$NO_X$ emissions are a potential contributor to secondary particulate formation. Since OPC is conducting a top-down BACT analysis for $NO_X$ for the proposed projects, secondary PM BACT is effectively addressed by reducing the direct emissions of $NO_X$. As such, secondary PM BACT is not separately addressed.

Identification of $NO_X$ Control Technologies – Combustion Turbines (Step 1)

$NO_X$ reduction can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of $NO_X$ formation (reducing peak flame temperature) or introduce inerts (combustion products, for example) that limit initial $NO_X$ formation, or both. Several post-combustion $NO_X$ control technologies could potentially be employed for the WCP turbines. These technologies use various strategies to chemically reduce $NO_X$ to $N_2$ with or without the use of a catalyst.

Detailed tables of BACT determinations from the RBLC database are provided in Appendix C of Volume I of the application. Using the RBLC search, as well as a review of technical literature, potentially applicable $NO_X$ control technologies for turbines were identified based on the principles of control technology and engineering experience for general combustion units.

Combustion control options include:[26]

- Water or Steam Injection
- Dry Low-$NO_X$ (DLN) Combustion Technology (such as SoLoNO$_X$™)
- Good Combustion Practices (Base Case)

Post-combustion control options include:

- EM$_X$™/SCONO$_X$™ Technology
- Selective Catalytic Reduction (SCR)
- SCR with Ammonia Oxidation Catalyst (Zero-Slip™)
- Selective Non-Catalytic Reduction (SNCR)
- Multi-Function Catalyst (METEOR™)

[25] Conservatively ignoring combustion efficiency losses, a 100 MW unit would be the equivalent of 341 MMBtu/hr.

[26] An additional combustion control technology potentially identified was XONON which was offered by Catalytica Energy Systems. Catalytica merged with NZ Legacy in 2007 to form Renergy Holdings Inc. In November 2007, Renergy sold its SCR catalyst and management services business (SCR-Tech, LLC). SCR-Tech, LLC was acquired by Steag Energy Services, LLC in 2016. Based on research, there is no company which currently makes XONON. As such, it is not considered available for this BACT analysis.

Each control technology is described in detail in the following sections.

Water or Steam Injection

Water or steam injection operates by introducing water or steam into the flame area of the gas turbine combustor. The injected fluid provides a heat sink that absorbs some of the heat of combustion, thereby reducing the peak flame temperature and reducing the formation of thermal $NO_X$. The water injected into the turbine must be of high purity such that no dissolved solids are injected into the turbine. Dissolved solids in the water may damage the turbine due to erosion and/or the formation of deposits in the hot section of the turbine. Although water/steam injection can reduce $NO_X$ emissions by over 60%, the lower average temperature within the combustor may produce higher levels of CO and VOC as a result of incomplete combustion.[27] Additionally, water/steam injection results in a decrease in combustion efficiency, an increase in power (due to increased mass flow), and an increase in maintenance requirements due to wear.[28]

Dry Low-$NO_X$ (DLN) Combustors

The lean premix technology, also referred to as dry low-$NO_X$ combustion technology, is a pollution prevention technology that minimizes $NO_X$ emissions by reducing the conversion of atmospheric nitrogen to $NO_X$ in the turbine combustor. This is accomplished by reducing the combustor temperature using lean mixtures of air and/or fuel staging or by decreasing the residence time of the combustor.[29] In lean combustion systems, excess air is introduced into the combustion zone to produce a significantly leaner fuel/air mixture than is required for complete combustion. This excess air decreases the overall flame temperature because a portion of the energy released from the fuel must be used to heat the excess air to the reaction temperature. Pre-mixing the fuel and air prior to introduction into the combustion zone provides a uniform fuel/air mixture and prevents localized high temperature regions within the combustor area.[30] Since $NO_X$ formation rates are an exponential function of temperature, a considerable reduction in $NO_X$ can be achieved by the lean pre-mix system.[31] Depending on the manufacturer and product, different levels of control efficiencies can be achieved.

Good Combustion Practices

Good combustion practices are those, in the absence of control technology, which allow the equipment to operate as efficiently as possible. The operating parameters most likely to affect $NO_X$ emissions include ambient temperature, fuel characteristics, and air-to-fuel ratios.

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[27] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[28] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[29] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[30] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[31] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

$EM_X^{TM}/SCONO_X$

$EM_X^{TM}$ (the second-generation of the $SCONO_X$ $NO_X$ Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both $NO_X$ and CO without a reagent, such as ammonia ($NH_3$). The $SCONO_X$ system consists of a platinum-based catalyst coated with potassium carbonate [$K_2(CO_3)$] to oxidize $NO_X$ (to potassium nitrate [$K(NO_3)$]) and CO (to $CO_2$).[32] Hydrogen ($H_2$) is then used as the basis for the catalyst regeneration process where $K(NO_3)$ is reacted to reform the $K_2(CO_3)$ catalyst and release nitrogen gas and water.[33] The catalyst is installed in the flue gas with a temperature range between 300°F to 700°F. The $SCONO_X$ catalyst is susceptible to fouling by sulfur if the sulfur content of the flue gas is high.[34]

Estimates of control efficiency for a $SCONO_X$ system vary depending on the pollutant controlled. California Energy Commission reports a control efficiency of 78% for $NO_X$ reductions down to 2.0 ppm, and even higher $NO_X$ reductions down to 1 ppm for some designs.[35]

Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment process in which $NH_3$ is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, $NH_3$ and NO react to form diatomic $N_2$ and $H_2O$ vapor. The overall chemical reaction can be expressed as:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

When operated within the optimum temperature range, the reaction can result in removal efficiencies between 70 and 90 percent.[36] Optimal temperatures for SCR units ranges from 480°F to 800°F and typical SCR systems can function effectively under temperature fluctuations of up to 200°F.[37] SCR can be used to reduce $NO_X$ emissions from combustion of natural gas and light oils (e.g., distillate). Combustion of heavier oils can produce high levels of particulate, which may foul the catalyst surface, reducing the $NO_X$ removal efficiency.[38] Other considerations include the

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[32] Georgia EPD, *Prevention of Significant Air Quality Deterioration Review Preliminary Determination – Dahlberg Combustion Turbine Electric Generating Facility*, October 2009. https://epd.georgia.gov/air/sites/epd.georgia.gov.air/files/related_files/document/1570034pd.pdf

[33] Georgia EPD, *Prevention of Significant Air Quality Deterioration Review Preliminary Determination – Dahlberg Combustion Turbine Electric Generating Facility*, October 2009. https://epd.georgia.gov/air/sites/epd.georgia.gov.air/files/related_files/document/1570034pd.pdf

[34] California Energy Commission, *Evaluation of Best Available Control Technology*, Appendix 8.1E, pages 8.1E-9 and 8.1E-10.

[35] California Energy Commission, *Evaluation of Best Available Control Technology*, Appendix 8.1E, page 8.1E-6.

[36] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[37] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[38] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

possibility for ammonia slip, which refers to emissions of unreacted ammonia escaping with the flue gas and its contribution to secondary particulate formation.[39]

SCR with Ammonia Oxidation Catalyst (Zero-Slip™)

SCR with Ammonia Oxidation Catalyst (Zero-Slip™) is a refinement on standard post-combustion SCR technology developed by Cormetech and Mitsubishi Power Systems to reduce ammonia slip associated with traditional SCR systems. The Zero-Slip™ technology consists of a second bed of catalyst that is installed after the main SCR catalyst to further react $NO_X$ with the ammonia. This results in $NO_X$ emissions on par with standard SCR systems and less ammonia slip (less than 2.0 ppmvd at 15% $O_2$).[40]

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion $NO_X$ control technology based on the reaction of urea or ammonia with $NO_X$. In the SNCR chemical reaction, urea [$CO(NH_2)_2$] or ammonia is injected into the combustion gas path to reduce the $NO_X$ to nitrogen and water. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + \tfrac{1}{2}\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$
$$4\ NH_3 + 6NO \rightarrow 5\ N_2 + 6\ H_2O$$

Typical removal efficiencies for SNCR range from 30 to 50 percent and higher when coupled with combustion controls.[41] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600°F to 2,000°F.[42] Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional $NO_X$.

Multi-Function Catalyst (METEOR™)

METEOR™ is a multi-pollutant post-combustion control technology originally developed and patented by Siemens Energy Inc. and optimized by Cormetech. The METEOR™ catalyst uses ammonia, similar to standard SCR systems, to reduce $NO_X$ emissions but is also able to reduce CO, VOC, and ammonia emissions using a single catalyst bed (i.e., eliminate the need for a separate oxidation catalyst system if CO and VOC reductions are required), resulting in reduced

[39] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.)

[40] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of $NO_X$, Attachment B pages 13-14.

[41] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Selective Non -Catalytic Reduction (SNCR), EPA-452/F-03-031.

[42] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Selective Non -Catalytic Reduction (SNCR), EPA-452/F-03-031.

pressure drop and parasitic load requirements.[43] The ability of the METEOR™ catalyst to reduce $NO_X$ emissions is on par with more traditional SCR designs.[44]

Elimination of Technically Infeasible $NO_X$ Control Options – Combustion Turbines (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control, if a control technology has not been commercially demonstrated to be achievable, or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

Water or Steam Injection Feasibility

Water or steam injection is a $NO_X$ reduction technology that is commonly used to control $NO_X$ emissions when fuel oil is burned, but is not as effective as DLN combustors when firing natural gas.[45] Water or steam injection also cannot be used in conjunction with DLN because it leads to unstable combustion and increases CO emissions.[46] As the WCP turbines utilize DLN combustors for natural gas combustion that reduce $NO_X$ emissions further than water or steam injection would, water or steam injection is deemed to be infeasible when combusting natural gas, but feasible for purposes of fuel oil combustion.

Dry Low $NO_X$ Combustion Technology Feasibility

Dry low $NO_X$ combustion technology is a $NO_X$ control technology that is integral to the combustion turbine. It is determined to be technically feasible for the combustion turbine itself for natural gas combustion and is currently installed on the WCP units. Therefore, DLN combustion technology is included in the following BACT steps for natural gas but represents part of the base case for $NO_X$ performance as it is inherent in the operation of the combustion systems.

[43] Siemens Energy and Cormetech, *Capital and O&M Benefits of Advanced Multi-Function Catalyst Technology for Combustion Turbine Power Plants,* Power Gen 2015, page 2.

[44] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of $NO_X$, Attachment B pages 15-16.

[45] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of $NO_X$, Attachment B page 12.

[46] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of $NO_X$, Attachment B page 12.

Good Combustion Practices Feasibility

Good combustion practices are those that allow equipment to operate as efficiently as possible and maintain minimal emission releases with or without the operation of other control technologies. This is considered technically feasible for the minimization of $NO_X$ emissions from the turbines.

$EM_X$™/$SCONO_X$™ Technology Feasibility

The $EM_X$™/$SCONO_X$™ catalyst system is a post-combustion technology that utilizes a proprietary oxidation catalyst and absorption technology using a single catalyst (potassium carbonate) for removal of $NO_X$, CO, and VOC without the use of ammonia. As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the $EM_X$™/$SCONO_X$™ catalyst system has operated successfully on several smaller, natural gas-fired combined-cycle units, but there are engineering challenges with applying this technology to larger plants with full scale operation.[47] Additionally, the operating range of the catalyst is 300 to 700°F, well below the exhaust temperature for simple-cycle combustion turbines.[48] Consequently, it is concluded that $EM_X$™/$SCONO_X$™ is not technically feasible for control of $NO_X$ emissions from the WCP turbines.

SCR Feasibility

Optimal temperatures for the operation of SCR ranges from 480°F to 800°F and typical SCR systems have the ability to function effectively under temperature fluctuations of up to 200°F.[49] Given the exhaust temperature of utility-scale simple cycle turbines is typically in excess of 1,000°F, use of SCR could be considered technically infeasible for such units.[50] However tempering air could potentially be added to such systems, at significant cost, to allow for use of SCR for such units, as has been done for smaller simple-cycle combustion turbine units. The problem with tempering air is the mass/volume of air required, as it is not just the higher temperature but also the larger volume of air flow involved with larger frame units. Therefore, a cost analysis has been conservatively included in Step 4 to ascertain feasibility.

SCR with Ammonia Oxidation Catalyst (Zero-Slip™) Feasibility

Based on WCP's review of available control technologies, to date, the Zero-Slip™ catalyst technology has not been demonstrated on large, utility-size units, with full scale operation

[47] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of $NO_X$, Attachment B pages 14.

[48] U.S. EPA Office of Air and Radition, *Final Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS: Assessment of Non-EGU $NO_X$ Emission Controls, Cost of Controls, and Time for Compliance Final TSD*, August 2016, Appendix A, Page 3-5. Docket ID No. EPA-HQ-OAR-2015-0500.

[49] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Catalytic Reduction (SCR)*, EPA-452/F-03-032.

[50] WCP turbine exhaust temperatures are represented as 1,113°F in the facility's Title V Renewal Application, dated December 11, 2019 (Submittal ID: 288236).

demonstrated on a 7.5 MW Solar Taurus combustion turbine.[51] In addition, this technology is essentially SCR with a focus on reducing ammonia slip; accordingly, as SCR has been deemed infeasible, as this technology has not been demonstrated on large, utility size units, and it would not achieve $NO_X$ emission rates lower than that achieved by conventional SCR designs, the Zero-Slip™ technology option is not considered a technically feasible control option.

SNCR Feasibility

The temperature range required for effective operation of this technology, 1,600 to 2,000°F, is above the peak exhaust temperature for the WCP turbine units.[52] In addition, a review of the RBLC database and AP-42's supplemental database for Chapter 3.1, *Stationary Gas Turbines*, April 2000, shows that SNCR has not been demonstrated on a turbine of this size. Given the changes to adapt units for use of SNCR, such as adding a flue gas heater, are not practical and reduces the energy efficiency of the generating units, SNCR is eliminated as a technically feasible option for control of $NO_X$ emissions from the WCP turbine systems.

Multi-Function Catalyst (METEOR™) Feasibility

The METEOR™ catalyst technology, developed and patented by Siemens Energy Inc., is currently only in use on one 320 MW Siemens/Westinghouse 501G combustion turbine installed in November 2015.[53,54] A review of the RBLC database for turbines similar to the WCP units did not

return any units that use the METEOR™ catalyst technology. As there is limited commercial operating experience with the METEOR™ catalyst, and the system would have similar technical considerations as a traditional SCR system, the METEOR™ technology option is not considered a technically feasible control option for purposes of BACT.

<u>Summary and Ranking of Remaining $NO_X$ Controls – Combustion Turbines (Step 3)</u>

Of the control technologies available for $NO_X$ emissions, the options technically feasible for each unit are shown in Table 4-1**.**

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[51] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of $NO_X$, Attachment B page 14.

[52] U.S. EPA, Clean Air Technology Center, *Air Pollution Control Technology Fact Sheet: Selective Non-Catalytic Reduction (SNCR)*, EPA-452/F-03-031.

[53] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of $NO_X$, Attachment B page 16.

[54] Siemens Energy and Cormetech, *Capital and O&M Benefits of Advanced Multi-Function Catalyst Technology for Combustion Turbine Power Plants*, Power Gen 2015, page 2.

**Table 4-1. Remaining $NO_X$ Control Technologies**

| Control Technology | Feasible For Natural Gas | Feasible for Fuel Oil | Estimated Efficiency |
|---|---|---|---|
| Water or Steam Injection | No | **Yes** | >60% |
| DLN Combustion Technology | **Yes** | No | Base Case |
| Good Combustion Practice | **Yes** | **Yes** | Base Case |
| $EM_X$™/$SCONO_X$™ Technology | No | No | Infeasible |
| SCR | **Yes** | **Yes** | 70-90% |
| SCR with Zero-Slip™ | No | No | Infeasible |
| SNCR | No | No | Infeasible |
| METEOR™ | No | No | Infeasible |

As shown in Table 4-1, the remaining potentially feasible control technologies could include SCR, DLN combustors (natural gas only), water or steam injection (fuel oil only), and good combustion practices. The WCP units already utilize DLN combustors for natural gas combustion.

Evaluation of Most Stringent $NO_X$ Controls – Combustion Turbines (Step 4)

Per Table 4-1, SCR is the highest ranking potentially feasible control technology for both natural gas and fuel oil combustion in the turbines. The estimated cost of controlling $NO_X$ using SCR for the WCP simple cycle turbines is approximately $20,000 per ton of $NO_X$ removed based on the detailed cost analysis provided in Appendix D of Volume I of the application, developed using the methods outlined by the U.S. EPA in the OAQPS guidance manual.[55] As previously discussed, estimated costs are high given the high volume of tempering air that would be required to reduce the turbine exhaust temperatures to an acceptable range for operation of the SCR. Therefore, WCP concludes that SCR is not cost effective and is not considered BACT for the Facility's turbines

For fuel oil combustion, the next highest ranked control system is a water or steam injection system. WCP is proposing to install a water injection system on the modified turbines as BACT; hence a cost-effectiveness calculation is not presented. Since the highest remaining control technology for fuel oil combustion has been selected as BACT, no further evaluation of remaining control technologies is required.

For natural gas combustion, DLN combustors are the next highest ranked control and represent the present technology in use for the WCP turbines. Therefore, DLN is selected as BACT for purposes of natural gas combustion.

[55] U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, EPA 452/B-02-001, July 2002. http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf Note that data from updated sections of the manual related to $NO_X$ control costs is utilized as applicable. For more details on the updating of the control cost manual see https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

Selection of Emission Limits and Controls for $NO_X$ BACT – Combustion Turbines (Step 5)

Once the proposed modifications are complete, the combustion turbine systems will be subject to an NSPS Subpart KKKK $NO_X$ emission standard of 15 ppm at 15% $O_2$ or 0.43 lb/MWh useful output during natural gas combustion; for fuel oil combustion the $NO_X$ emissions standard will be 42 ppm at 15% $O_2$ or 1.3 lb/MWh useful output. These NSPS Subpart KKKK limits serve as the floor for allowable $NO_X$ BACT limits. Each individual combustion turbine is presently subject to a $NO_X$ limit from NSPS Subpart GG per Condition 3.3.3 of Permit No. 4911-303-0039-V-08-0, however the NSPS Subpart GG limit will no longer apply as a result of applicability of the NSPS Subpart KKKK $NO_X$ limits.[56]

As the selected BACT technology for $NO_X$ emissions relies on DLN combustors and good combustion practices for natural gas, and water injection and good combustion practices for fuel oil combustion, WCP searched U.S. EPA's RBLC database for modifications of similar units at other facilities to determine what has been established as a BACT emission requirement for comparable operations. Numerous entries for natural gas or fuel oil simple cycle combustion turbines are provided in the RBLC summary table in Appendix C of Volume I of the application. Review of the RBLC entries confirms that controls for $NO_X$ emissions are typically DLN combustors (natural gas), water or steam injection (fuel oil), and good combustion practices for similarly sized simple cycle combustion turbines. "Good combustion practices" typically refers to practices inherent in the routine operation and maintenance of the generating unit, such as automated operating systems and periodic tuning of the turbines.

Once the technology is established, an emission limitation must be proposed, and review of the RBLC entries listed in Appendix C of Volume I of the application provides an indication of what has been established as BACT emission limitations for potentially similar units as those being modified by WCP. The majority of the RBLC database entries relate to the installation of new state-of-the-art simple cycle units, not modifications of existing simple cycle units. Given the advancements in turbine design and control systems, it is not anticipated that modification of an older generation turbine system would improve combustion efficiency, controls and performance in a manner that would be comparable to installation of a new, state-of-the-art turbine and controls system. Therefore, for comparison purposes, the RBLC entries of interest for WCP are those which include turbine units deemed to be potentially modified. A review of the RBLC database entries listed in Appendix C of Volume I of the application reveals that many of the entries do not provide sufficient detail to determine whether the turbines listed were to be newly constructed units or modified units.

For these RBLC entries, further research was conducted as needed using available permits, permit applications, and public documentation. The following qualifying criteria for potentially comparable units to the WCP turbines include:

- Turbine is existing and proposed a modification; exclude units proposed for initial construction;
- Control method includes DLN combustors (natural gas firing) or water injection (fuel oil firing) and does not include control technologies which have been deemed to be infeasible (i.e., SCR, SNCR);

[56] 40 CFR 60.4305(b)

- Units are similar GE Frame 7 units; and
- Units are utilized for the purposes of power generation and not utilized for other purposes such as compression.

This review has been conducted on a fuel-specific basis, detailed in the following sections.

Selection of Emission Limits for $NO_X$ BACT - Natural Gas Firing

Table 5-3 of Volume I of the application includes $NO_X$ RBLC database entries for turbine units combusting natural gas which are potentially comparable to the existing units at the WCP facility. Further research was performed for each of these entries using available permits, permit applications, and public documentation to analyze whether the turbine units are comparable to the existing units at the WCP facility. Findings and notes from this research are further detailed below.

Cunningham Station Power Plant

Southwestern Public Service Company is permitted to operate the Cunningham Station Power Plant, which incorporates the use of two 115 MW combustion turbines which were constructed in 1997. The turbines utilize DLN burners for control of $NO_X$ and are capable of operating with or without power augmentation, in which power output is increased by lowering air temperature through water injections into the compressor. On May 2, 2011, the Cunningham Station Power Plant was issued an NSR permit in which BACT limits for $NO_X$ were increased.[57] However, upon further investigation of the facility's historical permits, it was determined that the turbine units are Westinghouse 501D5A model turbines. Given the unique emission profiles associated with the manufacturer design of different natural gas simple cycle turbine units, WCP maintains that the Westinghouse model turbines are not necessarily an appropriate comparison for a GE 7FA turbine. However, it is worth noting that the permit issued on May 2, 2011 established a BACT emission limitation for $NO_X$ of 21 ppmvd (without power augmentation) at 15 percent $O_2$ which excludes periods of startup and shutdown. This $NO_X$ emission limitation is considered achievable for the existing WCP turbine units. A revised NSR permit was issued on May 23, 2012 which maintained the previously described BACT emission limits for $NO_X$.[58]

[57] NSR Permit No. PSD-NM-622-M3 issued by the NMED to the Southwestern Public Service Company on May 2, 2011.

[58] NSR Permit No. PSD-NM-622-M4 issued by the NMED to the Southwestern Public Service Company on May 23, 2012.

Calcasieu Plant

Calcasieu Power, LLC, received a state preconstruction and Part 70 operating permit from the Louisiana Department of Environmental Quality (LDEQ) on October 21, 1999 for the operation of a peaking power plant consisting of two natural gas fired, simple cycle combustion turbines with heat inputs of 1,900 MMBtu/hr.[59] Each of the combustion turbines utilize DLN combustors for emissions control. Effective March 2008, Entergy Gulf States Louisiana (Entergy), LLC purchased Calcasieu Power, LLC and the facility was thereafter referred to as the Calcasieu Plant.[60]

Entergy received an initial PSD permit and a revised Title V permit on December 21, 2011 which allowed for the two combustion turbines to increase annual operating hours.[61] The initial PSD permit provided a BACT emission limit for $NO_X$ during normal operation of 17.5 ppmvd corrected to 15% $O_2$ for each of the two turbines and required emissions of $NO_X$ to be monitored by a CEMs. However, the changes associated with the December 21, 2011 Title V and PSD permits were never incorporated, and Entergy requested the revocation of the PSD permit.[62] On January 25, 2013, the LDEQ issued Permit No. 0520-00219-V4 which removed the changes authorized per the December 21, 2011 Title V permit as well as increased the maximum hourly firing rate of the turbines to 2,200 MMBtu/hr. A new PSD permit and revised Title V permit were issued on June 1, 2015 which allowed for an increase in the combined operating time for the turbines and allowed for additional periods of startup/shutdown time. The June 1, 2015 PSD permit also established BACT emission limits for $NO_X$ of 34.3 ppmvd corrected to 15% $O_2$ during normal operation for each of the two turbines and required emissions of $NO_X$ to be monitored by CEM.

Although the make and model of the Calcasieu Plant turbines are not known, WCP anticipates that the $NO_X$ emission limit of 34.3 ppmvd is conservative and higher than other comparable BACT limitations.

Emporia Energy Center

Westar Energy received an Air Emissions Source PSD Construction Permit for the Emporia Energy Center on April 17, 2007 (modified May 5, 2011).[63] The Emporia Energy Center is a fossil fuel power plant which consists of four GE LM6000 PC natural gas fired, simple cycle combustion turbines equipped with water injection and three GE 7FA natural gas fired, simple cycle combustion turbines which utilize DLN burners.

The GE LM6000 PC model turbines are classified as aeroderivative gas turbines.[64] Aeroderivative turbines have a much smaller power output than what would be expected from a large frame unit

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[59] Permit No. 0520-00219-V0 issued by the LDEQ to Dynegy Operating Company, Inc. – Calcasieu Power, LLC, October 21, 1999.

[60] Per Notification of Ownership, Facility Name, and Operator Change submitted to the LDEQ on May 12, 2008.

[61] Permit Nos. 0520-00219-V3 and PSD-LA-746 issued by the LDEQ to Entergy Gulf States LA LLC, December 21, 2011.

[62] Per Title V Permit Renewal Renewal Application submitted to the LDEQ on April 11, 2012.

[63] Permit Nos. C-7072 and C-9132 issued by the KDHE on April 17, 2007 and May 5, 2011, respectively.

[64] https://www.ge.com/power/gas/gas-turbines/lm6000

such as a GE 7FA turbine; therefore, the GE LM6000 PC turbines cannot be considered relatively comparable units to reference for selection of BACT emission limits based on size.

The Emporia Energy Center does operate three GE 7FA simple cycle turbines with heat inputs of 1,780 MMBtu/hr which were authorized for construction in 2007. The GE 7FA turbines would be considered comparable in size and age to the existing units operated by WCP, and because both units are GE 7FA model turbines, it can be assumed that the turbines would have similar emission profiles. On March 18, 2013, the Kansas Department of Health and Environment (KDHE) issued an amendment to the prior PSD permit to add tuning language to allow for the periodic tuning of the GE 7FA combustion turbines.[65] The GE 7FA turbines at the Emporia Energy Center are subject to a $NO_X$ emission limitation of 9 ppmvd corrected to 15% $O_2$ on a 24-hr rolling average which excludes startup, shutdown, and malfunction periods. This BACT emission limit for $NO_X$ should be considered an achievable limit for the proposed modifications to the existing turbines at the WCP facility.

Doswell Energy Center

On October 4, 2016, the Virginia Department of Environmental Quality (VDEQ) issued a permit which authorized the addition of two natural gas fired GE 7FA simple cycle combustion turbines. Each turbine has a heat input of 1,961 MMBtu/hr and utilizes low $NO_X$ burners for control. The two turbines were originally constructed in 2001 and were to be relocated from an existing permitted site in Desoto, Florida to the Doswell Energy Center. Based on turbine age, model, and size these units should be considered comparable to the existing WCP turbines. Therefore, it is reasonable to assume that this modification is comparable to the proposed modification to the existing WCP turbine units. Each of the simple-cycle turbines added to the Doswell Energy Center are subject to BACT emission limitations for $NO_X$ of 9 ppmvd at 15% $O_2$ on a 3-hour average basis (averaging time based on the PSD permit), except during periods of startup, shutdown, and tuning. This is an achievable emission limitation for the existing WCP turbines at the WCP facility. Revised PSD permits for the two simple cycle combustion turbines were issued on May 31, 2018 and July 30, 2018. The issuance of the July 30, 2018 PSD permit revised the averaging period for the BACT emission limit for $NO_X$ from 3-hour averaging basis to a 1-hour averaging basis

Puente Power

The RBLC database entry for the Puente Power facility contained insufficient information needed to determine comparability relative to the proposed modified units at the WCP facility. Upon further research into publicly available information, it was discovered that the Puente Power facility was proposed for construction in 2015 in Ventura County, California. The proposed facility would consist of one natural gas fired, simple-cycle GE 7HA.01 turbine with a net-nominal 262 MW generating capacity.[66] However, in 2018, the California Energy Commission terminated the

[65] Permit No. C-10656 issued by the KDHE for the Emporia Energy Center on March 18, 2013.

[66] California Energy Commision, *Puente Power Project Final Staff Assessment Part 1*, Docket No. 15-AFC-01, Publication No. CEC-700-2016-006-FSA, December 8, 2016.

2015 application to construct the facility and the project was voided.[67] Therefore, as this project involved new units that were never constructed, the Puente Power RBLC database entry is not considered further in these BACT analyses

Waverly Facility (Waverly Power Plant)

In 1999, Pleasants Energy LLC submitted a permit application to the West Virginia Department of Environmental Protection (WVDEP) to construct a peaking power facility in Waverly, West Virginia which would utilize two GE 7FA natural gas fired, simple cycle combustion turbines capable of generating 300 MW. Natural gas was to be the primary fuel and fuel oil would be used as back-up.[68] The two combustion turbines were installed in 2001 and utilize DLN burners when firing natural gas and water injection for control of $NO_X$ when firing fuel oil.[69] The facility was issued a Permit to Modify on November 24, 2015 which allowed for the addition of two TurboPhase systems (8 engines) to allow for increased generator output.[70] The facility received an additional Permit to Modify on January 23, 2017, which allowed for the relaxation of limits which were originally imposed to maintain the synthetic minor status of the source for PSD permitting purposes.[71]

The authorization to operate the TurboPhase engines was removed by way of the Permit to Modify issued on March 13, 2018.[72] The Permit to Modify also allowed for the installation of "Advanced Gas Path" technology to the existing GE 7FA turbines which increased the maximum heat input of each turbine. The RBLC database entry for the issuance of the March 13, 2018 Permit to Modify states that the addition of the "Advanced Gas Path" technology to the combustion turbines was defined as a change in the method of operation that resulted in a major modification to the turbines. According to information available on General Electric's website, the incorporation of GE's "Advanced Gas Path" technology to GE 7FA turbines results in "increased output, efficiency, and availability, while reducing fuel consumption and extending gas turbine assets."[73]

The Waverly facility GE 7FA turbines have been modified since installation, albeit in ways that are not like the proposed WCP modifications. The BACT emission limits established per the 2013 and 2017 permitting actions is 9 ppm $NO_X$ at loads of 60% or higher based on a 30-day rolling average, excluding periods of startup and shutdown. This emission limit should be considered achievable for the existing turbines at the WCP facility.

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[67] Wendy Leung, "NRG proposal to build Puente Power Project on Oxnard coast is dead," *Ventura County Star*, December 17, 2018, https://www.vcstar.com/story/news/2018/12/17/power-plant-nrg-energy-inc-california-energy-commission-oxnard/2266774002/. (accessed January 21, 2021).

[68] West Virginia Department of Environmental Protection, Division of Air Quality, *Preliminary Determination/Fact Sheet for the Construction of Pleasants Energy, LLC's Waverly Power Plant located in Waverly, Pleasants County, WV*, Permit No. R14-0034, September 29, 2016.

[69] Per Section 1.1 of Permit No. R30-07300022-2020 issued by the WVDEP for the Waverly Facility on June 10, 2020.

[70] Permit No. R13-2373B issued by the WVDEP for the Waverly Facility on March 18, 2013.

[71] Permit No. R14-0034 issued by the WVDEP for the Waverly Facility on January 23, 2017.

[72] Permit No. R14-0034A issued by the WVDEP for the Waverly Facility on January 13, 2018.

[73] https://www.ge.com/power/services/gas-turbines/upgrades/advanced-gas-path?gecid=press_release.

Cameron LNG Facility

On October 1, 2013, the Cameron LNG Facility was issued an initial PSD permit and revised Title V permit which authorized the construction of additional equipment which included six refrigeration compressor turbines with heat inputs of 1,069 MMBtu/hr each.[74] The facility was again issued revised PSD and Title V permits on March 3, 2016 which authorized the construction of additional equipment, including four refrigeration compressor turbines with heat inputs of 1,069 MMBtu/hr each.[75] The RBLC database entry for the Cameron LNG Facility is associated with the February 17, 2017 issuance of revised PSD and Title V permits which incorporated two diesel tanks into the PSD permit and also incorporated administrative updates to both the PSD and Title V permits.[76] The RBLC entry for the Cameron LNG Facility did not provide sufficient detail to make a determination of comparability for these turbines. However, upon further review of PSD and Title V permits, it is clear that the turbines at the Cameron LNG Facility were constructed for the purposes of refrigeration compression rather than for power generation, and therefore they cannot be considered comparable to the existing turbine units at the WCP facility. Therefore, the Cameron LNG Facility RBLC database entry is not considered further in these BACT analyses.

Mustang Station

Mustang Station commenced operation of a 168 MW GE 7FA simple-cycle combustion turbine (Unit 6) in 2013. The turbine unit utilizes DLN burners for control of $NO_X$ emissions. The facility was issued an amended PSD permit on August 8, 2016 by the Texas Commission on Environmental Quality (TCEQ) which allowed for the combustion turbine to increase annual operation to 3,000 hours per year.[77] Because the turbine was built in 2013, the equipment at the Mustang Station represents new turbines, albeit GE 7FA turbines of a more modern design than those installed and operating at the WCP facility. The turbine at the Mustang Station may not be considered comparable to existing units at the WCP facility which began operation in 2001, yet the established BACT emission limitation, 9 ppm $NO_X$ corrected to 15 percent $O_2$ on a rolling 3-hour average (excluding periods of maintenance, startup, and shutdown) is considered achievable for the existing WCP turbine units.

Jackson County Generators

The Southern Power Company submitted an Air Preconstruction Permit General Application to the TCEQ in July 2014 for the construction of the Jackson County Generating Facility which would include four 230 MW natural gas fired simple cycle combustion turbines with DLN

[74] Permit Nos. PSD-LA-766 and 0560-00184-V5 issued by the LDEQ to Cameron LNG, LLC on October 1, 2013.

[75] Permit Nos. PSD-LA-766(M2) and 0560-00184-V7 issued by the LDEQ to Cameron LNG, LLC on March 3, 2016.

[76] Permit Nos. PSD-LA-766(M3) and 0560-00184-V8 issued by the LDEQ to Cameron LNG, LLC on February 17, 2017.

[77] Permits 72579, PSDTX1080M1, and GHGPSDTX138 issued by the TCEQ to Cameron LNG, LLC on October 1, 2013.

burners.[78] An initial permit was issued by the TCEQ on February 2, 2018.[79] Upon further investigation of the February 2018 permit, it was determined that the proposed units are Siemens F5 model turbines. Given the unique emission profiles associated with the manufacturer design of different natural gas simple cycle turbine units, WCP maintains that the Siemens F5 model turbines are not necessarily an appropriate comparison for a GE 7FA turbine. However, it is worth noting that the permit issued on February 2, 2018 established a BACT emission limitation for $NO_X$ of 9 ppmvd at 15 percent $O_2$ on a rolling 3-hour average which excludes periods of startup and shutdown. This $NO_X$ emission limitation is considered achievable for the existing WCP turbine units.

Ector County Energy Station

The Ector County Energy Station was issued initial permits for the construction of two simple cycle turbine generating units on August 1, 2014.[80] Subsequent revisions to the initial permit were issued in 2014, 2017, 2018, 2019, and 2020. The permit allowed for the construction of two GE 7FA.03 or 7FA.05 combustion turbines capable of generating 165-193 MW of output; per more recent documentation it appears the GE 7FA.03 engines were installed. Each of the turbines were to be controlled using DLN burners. An RBLC database entry associated with a permit issuance dated 8/17/2020 states that hours of operation for the existing combustion turbines were increased per this permitting action. As the initial air permit was received in 2014, it is reasonable to assume that the turbines at the Ector County Energy Station are newer state-of-the-art simple cycle combustion turbine units which would not necessarily be comparable to the existing WCP units. However, the units are subject to a 9 ppmvd $NO_X$ limit at 15% $O_2$ on a rolling 3-hour average which excludes periods of startup and shutdown. This $NO_X$ emission limitation is considered achievable for the existing WCP turbine units.

Summary – Natural Gas $NO_X$ BACT

The anticipated $NO_X$ BACT for natural gas firing would be good combustion practices and the use of DLN combustion technology. As was previously discussed, there are various factors as to why, even with the use of the same control technologies, the emissions limits presented for the facilities in Table 5-3 of Volume I of the application are not necessarily directly comparable to the WCP units. Table 4-2 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-3 of Volume I of the application are comparable to the WCP units based on these factors.

[78] Per the Air Preconstruction Permit General Application submitted by the Southern Power Company to TCEQ on July 11, 2014.

[79] Permits Nos. 121917 and PSDTX1422 issued by the TCEQ to the Southern Power Company on February 2, 2018.

[80] Permits Nos. 110423 and PSDTX1366 issued by the TCEQ to Invenergy Thermal Development LLC on August 1, 2014.

**Table 4-2. Unit Comparability for $NO_X$ Assessment – Natural Gas Firing**

| Site | Modification? | GE Frame 7 Turbine? | Comparable? | $NO_X$ Emission Limit | Averaging Period |
|---|---|---|---|---|---|
| Cunningham Station Power Plant | Increase $NO_X$ BACT Emission Limits | No, Westinghouse 501D5A | No | Not Comparable | |
| Calcasieu Plant [1] | Increase hours, heat input | Unknown | Yes | 34.5 ppmvd @ 15% $O_2$ | Annual Avg. |
| Emporia Energy Center – GE LM6000PC Units (Water Injection) [2] | N/A | No | No | Not Comparable | |
| Emporia Energy Center – GE LM6000PC Units (DLN) [2] | N/A | No | No | Not Comparable | |
| Emporia Energy Center – GE 7FA | No (New in 2007) Added Tuning Requirements in 2013 | Yes | No (New Unit) Yes (Engine Type) | 9.0 ppmvd @ 15% $O_2$ | 24-hr Rolling Avg. |
| Doswell Energy Center | Turbine Relocation | Yes | Yes | 9.0 ppmvd @ 15% $O_2$ | 3-hr Avg.(2016) 1-hr Avg (2018) |
| Puente Power | No - New | Yes | No | Application Revoked | |
| Waverly Facility - 2017 | Relaxed synthetic minor limits | Yes | Potentially | 9.0 ppmvd @ 15% $O_2$ | 30-day Rolling Avg. |
| Waverly Facility - 2018 | Increase heat input | Yes | Potentially | 9.0 ppmvd @ 15% $O_2$ | 30-day Rolling Avg. |
| Cameron LNG Facility | No – New | Compressor Turbines | No | Not Comparable | |
| Mustang Station | Increase hours | Yes, 2013 install | Potentially | 9.0 ppmvd @ 15% $O_2$ | 3-hr Rolling Avg. |
| Jackson County Generators | No | No, Siemens F5 | No | Not Comparable | |
| Ector County Energy Center | No (New in 2014), increased hours in 2020 | Yes | Potentially | 9.0 ppmvd @ 15% $O_2$ | 3-hr Rolling Avg. |

[1] PSD Permit No. PSD-LA-746 issued on December 21, 2011 listed a BACT limit for $NO_X$ of 17.5 ppmvd @ 15% $O_2$. However, this permit was requested for revocation in a 2012 Title V Renewal Application. PSD Permit No. PSD-LA-798 was issued on June 1, 2015 and established the BACT limit for $NO_X$ as 34.5 ppmvd @ 15% $O_2$.

[2] Please note that the RBLC database entries in Appendix C of Volume I of the application include two separate entries for the GE LM6000 PC Sprint turbines at the Emporia Energy Center. One entry lists water injection as a control method and the other lists dry low $NO_X$ burners as the control method.

BACT is to be set at the lowest value that is achievable. Per
Table 4-, the remaining potentially comparable turbine units each have $NO_X$ emission limits for BACT of 9 ppmvd at 15% $O_2$ or greater. A $NO_X$ limit of 9 ppmvd at 15% $O_2$ is an achievable

emission limitation for the turbine units at the WCP facility. **Therefore, WCP proposes a BACT limit for $NO_X$ of 9 ppmvd at 15%**

**$O_2$ on a 4-hr averaging basis when firing natural gas, excluding periods of startup and shutdown.** A 4-hr averaging period as documented per the CEMS is proposed for consistency with the NSPS Subpart KKKK monitoring requirements and to ensure WCP's ability to demonstrate continuous compliance and reasonably aligns with the other BACT limitations reviewed per
Table 4-2.

<u>Selection of Emission Limits for $NO_X$ BACT – Fuel Oil Firing</u>

Table 5-5 of Volume I of the application includes $NO_X$ RBLC database entries for turbine units combusting fuel oil which are potentially comparable to the existing units at the WCP facility. Further research was performed as necessary for entries using available permits, permit applications, and public documentation to analyze whether the turbine units are comparable to the existing units at the WCP facility.

The three facilities listed in Table 5-5 of Volume I of the application are Wolverine Power, and the Waverly Facility.

Wolverine Power

Wolverine Power Supply Cooperative, Inc was issued a permit to install a coal fired power plant in Presque Isle County, Michigan by the Michigan Department of Environmental Quality (MDEQ) on June 29, 2011.[81] The permit was subsequently revised on July 12, 2011. The permitted sources include a 540 MMBtu/hr ULSD fired turbine generator of unknown make and model which would be used to start the plant when there is no power available from the electric grid. The turbine was permitted for 500 hours of operation annually and would utilize good combustion control technology only (i.e., did not require water injection). However, plans to build the coal-fired power plant were discontinued in 2013 and the project was voided.[82] Because the turbine at the Wolverine Power facility was never built, the BACT limit has not been demonstrated in practice and the associated RBLC database entry is not considered further in these BACT analyses.

<u>Summary – Fuel Oil $NO_X$ BACT</u>

The anticipated $NO_X$ BACT for fuel oil firing would be good combustion practices and the use of water or steam injection. Table 4-3 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-5 of Volume I of the application are comparable to the WCP units based on these factors.

[81] Permit No. 317-07 issued by the MDEQ on June 29, 2011 and revised on July 12, 2011.

[82] "Wolverine Power scraps plan to build coal-fired plant," *UpNorthLive News on ABC*, Sinclair Broadcast Group, Inc., December 18, 2013, https://upnorthlive.com/news/neighborhood/wolverine-power-scraps-plan-to-build-coal-fired-plant. (accessed January 21, 2021).

**Table 4-3. Unit Comparability for $NO_X$ Assessment – Fuel Oil Firing**

| Site | Modification? | GE Frame 7 Turbine? | Comparable? | $NO_X$ Emission Limit | Averaging Period |
|---|---|---|---|---|---|
| Wolverine Power | No – New | Unknown | No | Project Voided – Facility Was Not Built | |
| Waverly Facility - 2017 | Relaxed synthetic minor limits | Yes | Potentially | 49 ppmvd | 30-day Rolling Avg. |
| Waverly Facility - 2018 | Increase heat input | Yes | Potentially | 42 ppmvd | 30-day Rolling Avg. |

For the potentially comparable turbine units listed in Table 4-3, the 42 ppmvd requirement is similar to the BACT floor limitation established per NSPS Subpart KKKK of 42 ppm at 15% $O_2$ or 1.3 lb/MWh useful output when firing fuel oil. Therefore, this NSPS Subpart KKKK limit represents the proposed $NO_X$ BACT limit for the WCP turbines when combusting fuel oil. Compliance with the NSPS KKKK $NO_X$ emission limit is determined on a 4-hour rolling average basis.[83] **As such, WCP proposes a BACT limit for $NO_X$ of 42 ppmvd at 15% $O_2$ on a 4-hour rolling average basis when firing fuel oil, excluding periods of startup and shutdown**. Compliance will be demonstrated via a CEMS.

Secondary BACT Limit – $NO_X$

The proposed primary BACT limits of 9.0 ppmvd and 42 ppmvd for natural gas and fuel oil firing, respectively, do not apply during periods of startup/shutdown. Secondary BACT limits are required given that the non-steady state operations during periods of startup and shutdown result in a substantially different $NO_X$ emissions profile as the combustion units are not operating in an ideal mode for managing combustion characteristics. WCP therefore proposes **a secondary BACT limit per turbine of 152.7 tpy on a rolling 12-month basis** to ensure the minimization of emissions during startup/shutdown periods.

EPD Review – NOx Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the NOx BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[84]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

The same resources have been utilized in preparing the Division's $PM_{10}$, CO, Greenhouse Gases and VOC BACT analyses.

[83] 40 CFR 60.4350(g), 40 CFR 60.4380(b)(1)

[84] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

After reviewing the RBLC Database and other research methods, as contacting the regulating agencies directly, to verify, if SCR technology has been successfully installed on Large-Frame Simple Cycle Combustion Turbines. The Division agrees as defined by the facility that Large-Frame Simple Cycle Combustion Turbines as having a rating of 100 MW or Greater. The facility's simple cycle combustion turbines are rated at 169 MW (577 MMBtu/hr). Aeroderivative Turbines are not considered to be Large Frame Combustion Turbines. The RBLC data was examined for the last ten years for simple cycle combustion turbines.

**<u>SCR Feasibility</u>**

The facility has submitted a cost analysis in Appendix D of Volume I of the application. The cost analysis conducted follows the traditional methods outline by the U.S. EPA OAQPS guidance manual on estimating control technology costs.[85]

The cost analysis conducted for SCR results in a control cost effectiveness in excess of $17,000/ton NOx removed. Therefore, the cost analysis demonstrates that SCR is not an economically feasible control option for NOx.

**<u>SCR Elimination</u>**

**Small-Size Combustion Turbines (*not in facility's spreadsheet) (9.8%)**

- Bayonne Energy Center, 60 MW each, 2 turbines, also subject to LAER.
- Perryman Generating Station, 60 MW each, 2 turbines, Water, and Steam Injection, also subject to LAER.
- Cove Point LNG Terminal, 65 MW each, 2 turbines, DLNs, also subject to LAER.
- Lonesome Creek, 3 Natural Gas Fired Simple Cycle Turbines; 412 MMBtu/hr.
- Pioneer Generating Station, Three GE LM6000 PC SPRINT natural gas fired turbines used to generate electricity for peak periods; Water injection; 451 MMBtu/hr.
- Cheyenne Prairie Generating Station, 3 GE LM6000 Simple Cycle Combustion Turbine (EP03, EP04, EP05), 40 MW EA. (They have an additional 2 CCTGs)

**Aeroderivative (4.9%)**

- Driftwood LNG Facility, 540 MMBtu/hr each, 20 turbines.
- Troutdale Energy Center, LLC, 653 MW, 3 GE LMS-100 combustion turbines, 1 CCCTG, 2 simple cycle CTGs with water injection. Utilize water injection when combusting natural gas or ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown; Limit the time in startup or shutdown. The SCR must be in use when the CCCTG is running and the P2 description for simple cycle CTs, includes that for the CCCTG. This has not been built. This facility can also belong in the next category.

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[85] U.S. EPA, OAQPS Control Cost Manual, 6th edition, EPA 452/B-02-001, July 2002. http://www.epa.gov/ttn/catc/dir1/c allchs.pdf, Note that data from updated sections of the manual related to NOx control costs is utilized as applicable. For more details on the updating of the control cost manual see https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations

- Pio Pico Energy Center, 3 General Electric (GE) LMS100 Natural Gas-Fired Combustion Turbine Generators (CTGS) Rated at 100 MW each. (Normal Operation, Startup, Shutdown). Water Injection. LAER.

**SCR only used in Combined Cycle Mode (*not in facility's spreadsheet) (8.2%)**

- Gaines County Power Plant, 227.5 MW ea., 4 Simple CTGs converted to 2, 2x1 CCCTGs
- PSEG Fossil LLC Sewaren Generating Station, 345 MW, 1 CCCTG, misdirected entry, only operates in combined cycle mode, subject to LAER.
- Cricket Valley Energy Center, 1 CCCTG, misdirected entry, only operates in combined cycle mode, subject to LAER, DLN.
- Cash Creek Generating Station, misdirected entry, only operates in combined cycle mode, DLN
- Pueblo Airport Generating Station, 799.7 MMBtu/hr ea., 2 Simple CTGs, DLNs.

Therefore, after this discussion and further review of the RBLC, GA EPD agrees that dry-low NOx burners for natural gas-fired operation and water injection for fuel oil-fired operation, represent NOx BACT control for simple cycle combustion turbines.

Conclusion – NOx Control

The technically feasible control technologies for NOx emission control for simple cycle turbines are SCR, DLN burners and water injection. Although high temperature SCR is technically feasible for simple-cycle turbines, this control technology has been demonstrated in practice only on aeroderivative-type simple-cycle turbines. High temperature SCR has not been commercially demonstrated for simple-cycle turbines in the size range selected for Plant Washington. Even if high temperature SCR were an option capable of reducing NOx emissions to 3 ppm when burning natural gas or fuel oil, this technology would cost between $15,000-$20,000/ton of NOx removed per GE 7FA gas turbine depending on the hours of oil burned. Consequently, high temperature SCR would not be cost effective on the simple-cycle turbines proposed. for the expansion at Plant Washington. Therefore, the combination of DLN combustors and water injection are the demonstrated and technically feasible options to be considered for this project.[86]

The only facilities with simple cycle combustion turbines that have installed an SCR are subject to LAER and those facilities with simple cycle combustion turbines of a comparative size have been aeroderivative turbines and/or have also been operating in combined cycle mode.

The Division agrees with the proposed BACT control technology of the use of dry-low NOx burners for natural gas-fired operation and water injection for fuel oil-fired operation for NOx control in the combustion turbines.

[86] This was concluded in the issued PSD permit for Plant Dahlberg, Permit No. 4911-157-0034-V-04-1 issued May 14, 2010, where they proposed to install 4 SGT6-5000F Simple Cycle CTGs with natural gas, and fuel oil backup with a fuel oil storage tank. The project was never built and the proposed equipment was removed from the permit.

The Division agrees with the proposed limits for normal operation that are the same limits as NSPS Subpart KKKK. **To account for emissions due to startup, shutdown or malfunction, the Division has decided to include the facility requested limit of 152.7 tons of NOx emissions (12 consecutive month average) firing natural gas or fuel oi**l from each of the combustion turbines (Source Codes: T1-T4).

The BACT selection for the combustion turbines (Source Codes: T1-T4) is summarized below in Table 4-4.

**Table 4-4: BACT Summary for the Combustion Turbines (Source Codes: T1-T4)**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| NOx | Dry Low NOx Burners (firing Natural Gas)<br><br>Water Injection (firing Fuel Oil) | 9 ppmvd @ 15% $O_2$<br><br>42 ppmvd @ 15% $O_2$ | 4 hours | NOx CEMS |
| NOx | Dry Low NOx Burners (firing Natural Gas)<br><br>Water Injection (firing Fuel Oil) | 152.7 tons* | 12 consecutive month average | NOx CEMS |

*Limit includes emissions during startup and shutdown.

**Combustion Turbines (Source Codes: T1-T4) – Particulate Matter, Particulate Matter Less than 10 Microns ($PM_{10}$), and Particulate Matter Less than 2.5 Microns ($PM_{2.5}$) Emissions**

Applicant's Proposal

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT on particulate related emissions from each simple-cycle turbine. The following sections contain details on the "top down" BACT review, as well as the control technology and emission limits selected as BACT for filterable PM and total $PM_{10}$/$PM_{2.5}$.

While BACT emission limits for $PM_{10}$ and $PM_{2.5}$ must include the condensable portion of particulate, most demonstrated control techniques are limited to those that reduce filterable particulate matter. As such, control techniques for filterable PM or $PM_{10}$ also reduce filterable $PM_{2.5}$. The PM BACT analyses for filterable PM and filterable $PM_{10}$ will also satisfy BACT for the filterable portion of $PM_{2.5}$. In the prepared BACT analyses, references to $PM_{10}$ are also relevant for $PM_{2.5}$. A potential source of secondary particulate matter from the proposed projects is due to $NO_X$ emissions from each combustion turbine. As WCP is completing a BACT review for $NO_X$ as part of this application, secondary PM BACT formation from $NO_X$ emissions will be indirectly addressed. The proposed project does not trigger PSD review for the $PM_{2.5}$ precursor $SO_2$, as project emissions increases are less than the applicable $SO_2$ SER. As such, secondary PM BACT is not required to be addressed separately.

PM Formation – Combustion Turbines

Filterable PM, $PM_{10}$ and $PM_{2.5}$ emissions from gas or distillate oil combustion result primarily from incomplete combustion and by ash and sulfur in the fuel.[87] Combustion of natural gas or distillate oil generates low PM emissions in comparison to other fuels due to the low ash and sulfur contents of these fuels.

In contrast to filterable particulate, condensable particulate is the portion of PM emissions that exhausts from the stack in gaseous form but condenses to form particulate matter once mixed with the cooler ambient air. Condensable particulate results from sulfur in the fuel and the resultant $H_2SO_4$, $NO_X$ being oxidized to nitric acid ($HNO_3$), and high molecular weight organics. A combustion turbine operating without an SCR will have lower condensable PM emissions than a similar unit operating with an SCR.

Identification of PM Control Technologies – Combustion Turbine (Step 1)

The following $PM_{10}$/$PM_{2.5}$ control technologies were identified based on a RBLC search, a limited review of information published in technical journals, and experience in conducting control technology reviews for similar types of equipment. Considering the physical and operational characteristics of the units, the candidate control options for particulate matter reduction include:

[87] AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*. April 2000.

- Multicyclone
- Wet Scrubber
- Electrostatic Precipitator (ESP)
- Baghouse
- Low sulfur fuel
- Good combustion and operating practices

Multicyclone

Multicyclones consist of several small cyclones operating in parallel. The cyclone creates a double vortex inside its shell, conveying centrifugal force on the inlet exhaust stream. The exhaust stream is then forced to move circularly through the cyclone, and the particulate matter in the stream is pushed to the cyclone walls. While this is effective for larger particles, smaller particles tend to be overtaken by the fluid drag force of the air stream and will depart the cyclones with the exiting air stream. The particulate removal in cyclones can be improved by having more complex gas flow patterns.[88] The control efficiency range for high efficiency single cyclones is 30 - 90% for $PM_{10}$ and 20 - 70% for $PM_{2.5}$. The use of multicyclones leads to greater PM control efficiency than from a single cyclone, resulting in control efficiencies in the range of 80-95% for particles greater than 5 microns in diameter ($PM_5$).[89] Multicyclones in parallel can typically handle a higher flowrate when compared to a single cyclone unit, up to approximately 106,000 standard cubic feet per minute (scfm). The allowable inlet gas temperature for a cyclone is limited by the type of construction material, but can be as high as 540°C (1,000°F).[90] Cyclones are generally used as precleaners for final control devices such as fabric filters/baghouses or ESPs due to the lower control efficiency of smaller particles from a cyclone.[91]

Wet Scrubber

Wet (in particular, venturi) scrubbers intercept dust particles using droplets of liquid (usually water). The larger, particle-enclosing water droplets are separated from the remaining droplets by gravity. The solid particulates are then separated from the water. The PM collection efficiencies of Venturi scrubbers range from 70% to greater than 99%, depending on the application. Collection efficiencies are generally higher for PM with aerodynamic diameters of approximately 0.5 µm ($PM_{0.5}$) to 5 µm ($PM_5$). Inlet gas temperatures for wet scrubbers usually range from 4 to 400°C (40 to 750°F), with typical gas flowrates for single-throat scrubbers ranging from 500 to 100,000 scfm.[92]

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88 U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005.

89 U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005

90 U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005

91 U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Cyclones, EPA-452/F-03-005

92 U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Venturi Scrubbers, EPA-452/F-03-017.

ESP

An ESP removes particles from an air stream by electrically charging the particles then passing them through a force field that causes them to migrate to an oppositely charged collector plate. After the particles are collected, the plates are knocked ("rapped"), and the accumulated particles fall into a collection hopper at the bottom of the ESP. The collection efficiency of an ESP depends on particle diameter, electrical field strength, gas flow rate, gas temperature, and plate dimensions. An ESP can be designed for either dry or wet applications.[93] An ESP can generally achieve approximately 99-99.9% reduction efficiency for PM emissions. Typical ESPs can handle approximately 1,000 to 100,000 scfm, at high temperatures up to 700°C (1,300°F).[94]

Baghouse (Fabric Filter)

A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Particulate laden gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse. The air cleaning process stops once the pressure drop across the filter reaches an economically unacceptable level. Typically, the trade-off to frequent cleaning and maintaining lower pressure drops is the wear and tear on the bags suffered in the cleaning process.[95] Typically, gas temperatures up to 260°C (500°F) can be accommodated routinely in a baghouse. The fabric filters have relatively high maintenance requirements (for example, periodic bag replacement), and elevated temperatures above the designed temperature can shorten the fabric life. Additionally, a baghouse/fabric filter cannot be operated in moist environments where the condensation of moisture could cause the filter to be plugged, reducing efficiency. Under the proper operating conditions, a baghouse can generally achieve approximately 99-99.9% reduction efficiency for PM emissions.[96]

Depending on the need, baghouses are available as standard units from the factory, or custom baghouses designed for specific applications. Standard baghouses can typically handle 100 to 100,000 scfm; while custom baghouses are generally larger, ranging from 100,000 to over 1,000,000 scfm.[97]

[93] Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996.

[94] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) – Wire-Pipe Type, EPA-452/F-03-027.

[95] Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems.* Barberton, OH: Babcock & Wilcox. November 1996.

[96] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Fabric Filter – Pulse-Jet Cleaned Type, EPA-452/F-03-025.

[97] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Fabric Filter – Pulse-Jet Cleaned Type, EPA-452/F-03-025.

Low Sulfur Fuels

Combusting pipeline-quality natural gas with an inherently low sulfur content reduces particulate emissions compared to other available fuels as there is less potential to form $H_2SO_4$. Similarly, use of ultra-low sulfur diesel fuel oil also minimizes $H_2SO_4$ formation leading to lower particulate emissions compared to other fuel oils.

Good Combustion and Operating Practices

Good combustion and operating practices imply that the unit is operated within parameters that, without significant control technology, allow the equipment to operate as efficiently as possible.

A properly operated combustion unit will minimize the formation of particulate emissions due to incomplete combustion. Good operating practices typically consist of controlling parameters such as fuel feed rates and air/fuel ratios and periodic tuning.

Elimination of Technically Infeasible PM Control Options – Combustion Turbines (Step 2)

All four of the add-on control technologies (multicyclones, wet scrubbers, ESPs, and baghouses) are technically infeasible for filterable particulate from natural gas combustion. Although the add-on control technologies identified are utilized in a number of processes to control particulate emissions, none of these add-on control technologies are applicable to natural gas-fired or fuel oil fired combustion turbines. Combustion of natural gas and ultra-low sulfur diesel generates relatively low levels of particulate emissions in comparison to other fuels due to the low ash and sulfur contents. In addition, turbines operate with a significant amount of excess air, which generates large exhaust flow rates. The low level of particulate emissions combined with the large exhaust gas volume results in very low concentrations of particulate.

Due to the low particulate concentration in the exhaust gas, add-on filterable particulate controls would not provide any significant degree of emission reduction for the combustion turbines and are therefore not considered further in this analysis.[98]

[98] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of particulates, page 43.

Summary and Ranking of Remaining PM Controls – Combustion Turbines (Step 3)

Of the control technologies available for $PM_{10}/PM_{2.5}$ emissions, the options technically feasible for each unit are shown in Table 4-5**.**

**Table 4-5. Remaining Particulate Matter Control Technologies**

| Control Technology | Technically Feasible for Combustion Turbine |
|---|---|
| Multicyclones | No |
| Wet Scrubber | No |
| ESP | No |
| Baghouse | No |
| Low Sulfur Fuel | Yes |
| Good Combustion and Operating Practices | Yes |

The remaining feasible control technologies include low sulfur fuels and good combustion and operating practices. Good combustion and operating practices in conjunction with low sulfur natural gas or ultra-low sulfur diesel combustion represents the base case for the combustion turbines. Therefore, as this is the highest-ranking feasible control remaining, it is selected as BACT.

Evaluation of Most Stringent PM Controls – Combustion Turbines (Step 4)

As stated previously, good combustion and operating practices with low sulfur natural gas or ultra-low sulfur diesel for the combustion turbines was determined as the most stringent filterable PM and total $PM_{10}/PM_{2.5}$ control that is a technically feasible option

Selection of Emission Limits and Controls for PM BACT – Combustion Turbines (Step 5)

The simple cycle combustion turbines will not be subject to any NSPS or NESHAP standard for $PM/PM_{10}/PM_{2.5}$ and thus there is no floor of allowable $PM/PM_{10}/PM_{2.5}$ BACT limits. The units are also not subject to any PM emission limit per the GRAQC.

As the selected BACT for particulate matter emissions relies on good combustion and operating practices in conjunction with the use of low sulfur natural gas or ultra-low sulfur diesel, WCP searched U.S. EPA's RBLC database for modifications of similar units at other facilities to determine what has been established as a BACT emission requirement for comparable operations. Numerous entries for natural gas and fuel oil fired simple-cycle systems are provided in Appendix C of Volume I of the application. Review of the RBLC entries confirms that add-on control for particulate emissions is not required for natural gas-fired or fuel oil fired simple cycle combustion turbines. Typical listings denote "good combustion practices" or similar variants. "Good combustion practices" typically refers to practices inherent in the routine operation and maintenance of the generating unit, such as automated operating systems and periodic tuning of the turbines.

Once the technology is established, an emission limitation must be proposed, and review of the RBLC entries provides an indication of what has been considered appropriate BACT emission limitations for potentially similar units as those being modified by WCP. As discussed previously, the following qualifying criteria were relied upon in review of the RBLC entries per Appendix C of Volume I of the application to identify potentially comparable units to the WCP turbines:

- Turbine is existing and proposed for a modification; exclude units proposed for initial construction,
- Units are similar GE Frame 7 units, and
- Units are utilized for the purposes of power generation and not utilized for other purposes such as compression.

This review has been conducted on a fuel-specific basis, detailed in Table 5-8 of Volume I of the application.

A review of the proposed control technologies for these facilities shows that use of good combustion practices and pipeline quality natural gas are common requirements for BACT. WCP already incorporates the use of good combustion practices and utilizes pipeline quality natural gas as fuel for the existing turbine systems.

For the units detailed in Table 5-11 of Volume I of the application that are potentially comparable to the modified WCP units, most limits for total $PM_{10}$/total $PM_{2.5}$ are specified in terms of lb/hr. As this mass emission rate is dependent on the size of the combustion turbine, a direct comparison in terms of lb/hr is not appropriate. To facilitate a limit comparison, where information was readily available, an equivalent lb/MMBtu has been estimated. Based on the available data, the range of BACT limits for TPM/$TPM_{10}$/$TPM_{2.5}$ when combusting natural gas is between 0.00686 – 0.0105 lb/MMBtu for units that are potentially comparable to the WCP turbines.

A historical review of information available for the WCP turbines when installed indicates a 19 lb/hr Total Suspended Particulate (TSP) and $PM_{10}$ guarantee. Given installation of the units in the early 2000s, these guarantees were likely intended to be filterable values based on Method 5 test methods. WCP, not the original site owners, does not have testing data related to the original turbine commissioning, nor has any recent PM related testing been conducted. When looking at the range of potential BACT limits (0.00686 – 0.0105 lb/MMBtu) and the heat input capacity of 1,766 MMBtu/hr for natural gas, the equivalent lb/hr rates would range from 12.1 – 18.5 lb/hr for total PM/$PM_{10}$/$PM_{2.5}$. As the highest lb/hr from the range for total PM is slightly less than the original manufacturer guarantee for filterable PM, WCP is proposing a BACT value that is higher than those summarized the in Table 5-9 of Volume I of the application.

<u>Summary Natural Gas BACT</u>

If WCP relied on AP-42 for determining condensable emissions from the turbines 8.3 lb/hr of condensable PM would be estimated, leading to an estimated total PM/$PM_{10}$/$PM_{2.5}$ of 27.3 lb/hr (0.0155 lb/MMBtu) when combined with the filterable PM guarantee.[99] However, WCP recognizes there is likely some conservatism in both the original guarantee and the AP-42 factor. Given the challenges associated with accurate measurement of condensables, and the lack of available test data for the WCP turbines, **WCP is proposing a BACT emission limit for each turbine of 24.2 lb/hr for total PM/$PM_{10}$/$PM_{2.5}$, equivalent to an emission rate of**

[99] 1,766 MMBtu/hr (natural gas capacity) * 4.7E-3 lb condensables/MMBtu. Emission factor for Condensable PM is obtained from AP-42 Section 3.1, *Stationary Gas Turbines*, Table 3.1-2a (April 2000).

**0.0137 lb/MMBtu.** Compliance with this BACT limit will be demonstrated by stack testing via U.S. EPA Method 5 and/or 201A in conjunction with Method 202 or alternative methods as appropriate.

Selection of Emission Limits for PM BACT – Fuel Oil Firing

Table 5-10 of Volume I of the application includes PM RBLC database entries for turbine units combusting fuel oil which may be potentially comparable to the existing units at the WCP facility.

The two facilities listed in Table 5-10 of Volume I of the application are Wolverine Power, and the Waverly Facility.

Summary – Fuel Oil PM BACT

The anticipated PM BACT for fuel oil firing will be good combustion practices and the use of ultra-low sulfur diesel. As was previously discussed, there are various factors as to why, even with the use of the same control technologies, the emissions limits presented for the facilities in Table 5-10 of Volume I of the application are not necessarily directly comparable to the WCP units. Table 5-11 of Volume I of the application summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-10 of Volume I of the application are comparable to the WCP units based on these factors.

For the units detailed in Table 5-11 of Volume I of the application that are potentially comparable to the modified WCP units, the limits for total PM/$PM_{10}$/total $PM_{2.5}$ are specified in terms of lb/hr. As this mass emission rate is dependent on the size of the combustion turbine, a direct comparison in terms of lb/hr is not appropriate. To facilitate a limit comparison, where information was readily available, an equivalent lb/MMBtu has been estimated. Based on the available data, the range of BACT limits for TPM/$TPM_{10}$/$TPM_{2.5}$ when combusting fuel oil is between 0.0194 – 0.0248 lb/MMBtu for units that are potentially comparable to the WCP turbines.

Based on emissions information specific to turbines operated elsewhere by the owners of the WCP facility, **WCP proposes a BACT emission limit for each simple-cycle system of 26.8 lb/hr for filterable PM/total $PM_{10}$/$PM_{2.5}$, equivalent to an emission rate of 0.0142 lb/MMBtu.** Compliance with this BACT limit will be demonstrated by stack testing via U.S. EPA Method 5 and/or 201A in conjunction with Method 202 or alternative methods as appropriate.

Secondary BACT Limit – PM

Secondary BACT limits are not proposed as the particulate emissions of the combustion turbines are not considered to be dependent on control measures with varying effectiveness nor will they vary substantially in startup or shutdown modes

EPD Review – Particulate Matter, Particulate Matter Less than 10 Microns ($PM_{10}$), and Particulate Matter Less than 2.5 Microns ($PM_{2.5}$) Emissions

The RBLC database was reviewed, with the intent of finding similarly sized facilities, of similar installation time period, and facilities that had modified the existing process. Also, with a focus of finding similar GE 7FA CTGs in use, at the facility, as possible. The Division has prepared a PM/$PM_{10}$/$PM_{2.5}$ BACT comparison spreadsheet for the similar units using the above-mentioned resources.

GA EPD agrees that pipeline quality natural gas and ULSD fuel represents BACT control technology for PM/$PM_{10}$/ $PM_{2.5.}$ The draft permit restricts fuel usage for natural gas to 12,000 hours of operation during any 12 consecutive months. ULSD is limited to 2,000 hours of operation during any twelve consecutive months.

The Mustang Facility which is comparable to WCP since it has an existing 162.8 MW GE7FA combustion turbine and is limited to 3,000 hours on natural gas. The PM limit chosen for BACT is 27 lb/hr for natural gas, comparable to WCP's proposed BACT limit of 24.2 lbs/hr natural gas.

The Waverly Facility which is comparable to WCP since it has 2 existing 150 MW GE7FA combustion turbine and has a 15 lb/hr NG limit (less than the performance guarantee) and 39 lb/hr FO limit (higher than WCP's proposed limit).

Most of the Facility's BACT limits were for newer units, different combustion turbine type, and size, therefore the limits were not comparable for the WCP combustion turbines.

EPD Conclusion – Particulate Matter, Particulate Matter Less than 10 Microns ($PM_{10}$), and Particulate Matter Less than 2.5 Microns ($PM_{2.5}$) Emissions Control

In comparing the facility to other similarly modified units, the Division agrees with the proposed limit of 24.2 lb/hr, natural gas and 26.8 lb/hr fuel oil based on performance guarantees for the combustion turbines (Source Codes: T1-T4), along with good combustion control.

In the Division's review of the RBLC data reveals that the primary control technology for PM emissions are good combustion and operating practices, and low sulfur fuels such as natural gas. The results are summarized in Table 4-6.

**Table 4-6: PM/$PM_{10}$/ $PM_{2.5}$ BACT Summary for the Combustion Turbine**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| Filterable PM/Total $PM_{10}$/Total $PM_{2.5}$ | Good Combustion and Operating Practices, and Low Sulfur Fuels | 24.2 lb/hr NG<br>26.8 lb/hr FO | hourly | Performance Test |

## Combustion Turbines CO Assessment

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT for CO emissions from each combustion turbine. The following sections details the "top down" BACT review, as well as the control technology and emission limits that are selected as BACT for CO.

CO Formation – Combustion Turbines

CO from combustion turbines is a by-product of incomplete combustion. Conditions leading in incomplete combustion can include insufficient oxygen availability, poor fuel/air mixing, reduced combustion-temperature, reduced combustion gas residence time, and load reduction. In addition, combustion modifications taken to ensure $NO_X$ emissions remain low may result in increased CO emissions.

Identification of CO Control Technologies – Combustion Turbines (Step 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques such as oxidation catalyst and combustion process design and good combustion practices.

Oxidation Catalysts

An oxidation catalyst is a post-combustion control technology that utilizes a catalyst to oxidize CO at lower temperatures. The addition of a catalyst to the basic thermal oxidation process accelerates the rate of oxidation by adsorbing oxygen from the air stream and CO in the waste stream onto the catalyst surface to react to form $CO_2$ and $H_2O$.

$EM_X^{TM}$/$SCONO_X^{TM}$

$EM_X^{TM}$ (the second-generation of the $SCONO_X$ $NO_X$ Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both $NO_X$ and CO without a reagent, discussed previously for the NOx Controls discussion.

Combustion Process Design and Good Combustion Practices

To minimize incomplete combustion and the resulting formation of CO, this control technology includes proper equipment design, proper operation, and good combustion practices. Proper equipment design is important in minimizing incomplete combustion by allowing for sufficient residence time at high temperature as well as turbulence to mitigate incomplete mixing. Generally, the effect of combustion zone temperature and residence time on CO emissions is the opposite of their effect on $NO_X$ emissions. Accordingly, it is critical to optimize oxygen availability with input air, while controlling temperature to minimize $NO_X$ formation.

Elimination of Technically Infeasible CO Control Options – Combustion Turbines (Step 2)

The second step in the BACT process is the elimination of technically infeasible control options based on process-specific conditions that prohibit implementation of the control, or the lack of commercial demonstration of achievability.

Oxidation Catalyst

Catalytic oxidizers typically operate within a temperature range between 600 to 800°F.[100] Given the exhaust temperature of utility-scale simple-cycle combustion turbines is typically in excess of 1,000°F, use of oxidation catalyst could be considered technically infeasible, although the possibility of utilizing tempering air to reduce the inlet exhaust temperature, at substantial costs, exists. Therefore, oxidation catalyst is considered technically feasible for installation on the Facility's combustion turbines and will be considered further in Step 4 to evaluate cost effectiveness.

$EM_X^{TM}/SCONO_X^{TM}$

The $EM_X^{TM}/SCONO_X^{TM}$ catalyst system is a post-combustion technology that utilizes a proprietary oxidation catalyst and absorption technology using a single catalyst (potassium carbonate) for removal of $NO_X$, CO, and VOC without the use of ammonia. As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the $EM_X^{TM}/SCONO_X^{TM}$ catalyst system has operated successfully on several smaller, natural gas-fired combined-cycle units, but there are engineering challenges with applying this technology to larger plants with full scale operation.[101] Additionally, the operating range of the catalyst is 300 to 700°F, well below the exhaust temperature for simple cycle combustion turbines.[102] Consequently, it is concluded that $EM_X^{TM}/SCONO_X^{TM}$ is not technically feasible for control of CO emissions from the WCP turbines.

Combustion Process Design and Good Combustion Practices

This represents the base case for design and operation of the simple cycle combustion turbines.

Summary and Ranking of Remaining CO Controls – Combustion Turbines (Step 3)

As detailed in the Step 2 analysis for CO, the only add-on control technically feasible to reduce emissions below the base case (Combustion Process Design and Good Combustion Practices) is oxidation catalyst. As a technically feasible control option, it must be evaluated further in the BACT process.

[100] U.S. EPA, CATC Fact Sheet for Catalytic Incineration, EPA-452/F-03-018. Available at: www.epa.gov/ttn/catc/dir1/fcataly.pdf

[101] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of $NO_X$, Attachment B pages 14.

[102] U.S. EPA Office of Air and Radition, *Final Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS: Assessment of Non-EGU $NO_X$ Emission Controls, Cost of Controls, and Time for Compliance Final TSD*, August 2016, Appendix A, Page 3-5. Docket ID No. EPA-HQ-OAR-2015-0500.

Evaluation of Most Stringent CO Controls – Combustion Turbines (Step 4)

Oxidation catalyst is the highest ranking potentially feasible control technology for both natural gas and fuel oil combustion in the turbines. The estimated cost of controlling CO using oxidation catalyst for the WCP turbines is more than $28K per ton of CO removed based on the detailed cost analysis provided in Appendix D of Volume I of the application, developed using the methods outline by the U.S. EPA in the OAQPS guidance manual.[103] Similar to the technical challenges discussed for SCR for $NO_X$ emissions reductions, estimated costs are high given the high volume of tempering air that would be required to reduce the turbine exhaust temperatures to an acceptable range for operation of an oxidation catalyst. Therefore, WCP concludes that an oxidation catalyst is not cost effective and is not considered BACT for the Facility's turbines

Therefore, combustion process design and good combustion practices represent BACT for the Facility's combustion turbines for CO.

Selection of Emission Limits and Controls for CO BACT – Combustion Turbines (Step 5)

The simple-cycle combustion turbines are not presently subject to a CO emission limit and NSPS Subpart KKKK does not establish emission standards for CO. Accordingly, a BACT floor for CO does not exist.

As the selected BACT for CO emissions relies on the combustion process design and good combustion practices, WCP searched U.S. EPA's RBLC database for modifications of similar units at other facilities to determine what has been established as a BACT emission requirement for comparable operations. Numerous entries for natural gas or fuel oil simple-cycle combustion turbines are provided in the RBLC summary table in Appendix C of Volume I of the application. Review of the RBLC entries confirms that BACT for CO emissions are typically combustion process design and good combustion practices for similarly sized simple-cycle combustion turbines. "Good combustion practices" typically refers to practices inherent in the routine operation and maintenance of the generating unit, such as automated operating systems and periodic tuning of the turbines.

Once the technology is established, an emission limitation must be proposed, and review of the RBLC entries provides an indication of what has been considered appropriate BACT emission limitations for potentially similar units as those being modified by WCP. As discussed previously, the following qualifying criteria were relied upon in review of the RBLC entries per Appendix C of Volume I of the application to identify potentially comparable units to the WCP turbines. For these RBLC entries, further research was conducted as needed using available permits, permit applications, and public documentation. The following qualifying criteria for potentially comparable units to the WCP turbines include:

- Turbine is existing and proposed a modification; exclude units proposed for initial construction;

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[103] U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, EPA 452/B-02-001, July 2002. http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf
For more details on the updating of the control cost manual see https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

- Control method does not include control technologies which have been deemed to be infeasible (i.e., Oxidation Catalyst, $EM_X^{TM}$/$SCONO_X^{TM}$);
- Units are similar GE Frame 7 units; and
- Units are utilized for the purposes of power generation and not utilized for other purposes such as compression.

This review has been conducted on a fuel-specific basis, detailed in the following sections.

Selection of Emission Limits for CO BACT - Natural Gas Firing

Table 5-12 of Volume I of the application includes CO RBLC database entries for turbine units combusting natural gas which are potentially comparable to the existing units at the WCP facility.

The RBLC entries detailed in Table 5-12 of Volume I of the application includes potential modifications at facilities which were discussed in the previous section. Many of the RBLC database entries have been conservatively included in the table as they could not be ruled out as units proposed for construction based on information presented in the RBLC database entry alone. As was previously stated, further review of available air permits, permit applications, and other facility documentation proved that many of the turbine units associated with these RBLC database entries are not comparable to the WCP turbine units.

A review of the proposed control technologies for these facilities shows that use of good combustion practices and pipeline quality natural gas are common requirements for BACT. WCP already incorporates the use of good combustion practices and utilizes pipeline quality natural gas as fuel for the existing turbine systems. WCP will continue to utilize those controls as BACT when firing natural gas in the turbines.

Table 5-13 of Volume I of the application summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-12 of Volume I of the application are comparable to the WPC units based on these factors.

As detailed in Table 5-13 of Volume I of the application, potentially comparable engines combusting natural gas have CO emission limits ranging from 4.0 – 15.83 ppmvd at 15% $O_2$. Multiple units are subject to a 9 ppm CO limit, which is equivalent to GE's guarantee for the WCP turbines when utilizing good combustion process design, good combustion practices, and pipeline quality natural gas. Although the lowest BACT limit for CO identified in the table is 4.0 ppmvd at 15% $O_2$ based on a one hour averaging period, WCP does not anticipate that the existing turbine units at the facility are capable of achieving this rate. **WCP proposes a BACT limit for CO of 9.0 ppmvd at 15% $O_2$ on a 3-hr averaging basis when firing natural gas, excluding periods of startup and shutdown.** WCP anticipates conducting performance testing to document continuous compliance with the proposed CO BACT limit using a 3-hr averaging period.

Selection of Emission Limits for CO BACT – Fuel Oil Firing

Table 5-14 of Volume I of the application includes a CO RBLC database entry for turbine units combusting fuel oil which are potentially comparable to the existing units at the WCP facility.

Summary Fuel Oil CO BACT

The anticipated BACT for CO when firing fuel oil would be combustion process design and good combustion practices. Table 4-7 summaries whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-14 of Volume I of the application are comparable to the WCP units based on these factors.

**Table 4-7. Unit Comparability for CO Assessment – Fuel Oil Firing**

| Site | Modification? | GE Frame 7 Turbine? | Comparable? | CO Emission Limit | Averaging Period |
|---|---|---|---|---|---|
| Wolverine Power | No – New | Unknown | No | Project Voided – Facility Was Not Built | |
| Waverly Facility - 2017 | Relaxed synthetic minor limits | Yes | Potentially | 20 ppmvd | 30-day Rolling Avg. |
| Waverly Facility - 2018 | Increase heat input | Yes | Potentially | 20 ppmvd | 30-day Rolling Avg. |

As can be noted in Table 4-7, the potentially comparable turbine units are subject to CO limits of 20 ppm at 15% $O_2$. This limit is also consistent with the BACT limitation for CO of 20 ppmvd at 15% $O_2$ on a rolling 3-hour averaging basis for the Hill County Generating Facility which can be referenced in Appendix C of Volume I of the application. Although the turbine units at the Hill County Generating Facility are proposed for construction and therefore cannot necessarily be considered directly comparable to the WCP turbine units, it is worth noting the similarities between the CO BACT limitations for the newer state-of-the-art turbines proposed at that facility and the CO BACT limitations for the potentially comparable units in Table 4-7. As such, **WCP proposes a CO BACT emission limit for each simple-cycle system of 20.0 ppmvd at 15% $O_2$ on a 3-hr averaging basis when firing fuel oil, excluding periods of startup and shutdown.** WCP anticipates conducting performance testing to document continuous compliance with the proposed CO BACT limit using a 3-hr averaging period.

Secondary BACT Limit – CO

The proposed primary BACT limits of 9.0 ppmvd and 20 ppmvd for natural gas and fuel oil firing, respectively, do not apply during periods of startup/shutdown. Secondary BACT limits are required given that the non-steady state operations during periods of startup and shutdown result in a substantially different CO emissions profile as the combustion units are not operating in an ideal mode for managing combustion characteristics. **WCP therefore proposes a secondary CO BACT limit per turbine of 70.9 tons of CO emission on a 12 consecutive month average to ensure the minimization of emissions during startup/shutdown periods when firing fuel oil or natural gas.**

EPD Review – Carbon Monoxide (CO) Emissions

The RBLC database was reviewed, with the intent of finding similarly sized facilities, of similar installation time period, and facilities that had modified the existing process. Also, with a focus of finding similar GE 7FA CTGs in use, at the facility, as possible. The Division has prepared a CO BACT comparison spreadsheet for the similar units using the resources, as discussed in the NOx BACT review.

GA EPD agrees that pipeline quality natural gas and ULSD fuel represents BACT control technology for CO. The draft permit restricts fuel usage for natural gas to 12,000 hours of operation during any 12 consecutive months. ULSD is limited to 2,000 hours of operation during any twelve consecutive months.

The Mustang Facility which is comparable to WCP since it has an existing 162.8 MW GE7FA combustion turbine and is limited to 3,000 hrs on natural gas. The CO limit chosen for BACT is 9.0 ppm for natural gas, similar to WCP's proposed BACT limit of 9.0 ppm for natural gas.

The Waverly Facility which is comparable to WCP since it has 2 existing 150 MW GE7FA combustion turbine and has a 9 ppm NG limit and 20 ppm FO limit.

Of a total of 69 Facility CO BACT limits, 17 facilities (24.6%) had the 9.0 ppm limit for natural gas despite being new or existing units, therefore this limit is a common choice for the CO BACT limit for natural gas.

EPD Conclusion – CO Emissions Control

In comparing the facility to other similarly modified units, the Division agrees with the proposed limit of 9.0 ppm natural gas and 20.0 ppm fuel oil for the combustion turbines (Source Codes: T1-T4), along with good combustion control.

In the Division's review of the RBLC data reveals that the primary control technology for CO emissions are good combustion and operating practices, and low sulfur fuels such as natural gas. The results are summarized in Table 4-8.

**Table 4-8: CO BACT Summary for the Combustion Turbine**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| CO | Good Combustion and Operating Practices, and Low Sulfur Fuels | 9 ppm NG<br>20 ppm FO | hourly | Performance Test |

## Combustion Turbines VOC Assessment

This section contains a review of pollutant formation, possible control technologies, and the ranking and selection of such controls with associated emission limits, for proposed BACT for VOC emissions from each combustion turbine. The following sections details the “top down” BACT review, as well as the control technology and emission limits that are selected as BACT for VOC.

Identification of VOC Control Technologies – Combustion Turbines (Step 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques such as oxidation catalyst and combustion process design and good combustion practices.

Oxidation Catalysts

An oxidation catalyst is a post-combustion technology wherein the products of combustion are introduced to a catalytic bed prompting the VOC to react with oxygen present in the exhaust stream, converting to carbon dioxide and water vapor. The overall control efficiency of such systems on VOC constituents is dependent on the individual VOC components. For example, research completed by U.S. EPA as part of MACT rulemakings found that control of formaldehyde emissions typically exceed 90%, but other pollutants such as benzene may not see any beneficial reductions. Hence, the overall range of VOC control can vary substantially.[104]

$EM_X$™/$SCONO_X$™

$EM_X$™ (the second-generation of the $SCONO_X$ $NO_X$ Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both $NO_X$ and CO, as well as VOC without a reagent.

Combustion Process Design and Good Combustion Practices

To minimize incomplete combustion and the resulting formation of VOC, this control technology includes proper equipment design, proper operation, and good combustion practices. Proper equipment design is important in minimizing incomplete combustion by allowing for sufficient residence time at high temperature as well as turbulence to mitigate incomplete mixing. Proper operation and good combustion practices provide additional VOC control via the use of gaseous fuels for good mixing and proper combustion techniques such as optimizing the air to fuel ratio.

Elimination of Technically Infeasible VOC Control Options – Combustion Turbines (Step 2)

The second step in the BACT process is the elimination of technically infeasible control options based on process-specific conditions that prohibit implementation of the control, or the lack of commercial demonstration of achievability.

[104] U.S. EPA Office of Air Quality Planning and Standards Memorandum, *Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines*, August 21, 2001.

Oxidation Catalyst

Catalytic oxidizers typically operate within a temperature range between 600 to 800°F.[105] Given the exhaust temperature of utility-scale simple cycle combustion turbines is typically in excess of 1,000°F, use of oxidation catalyst could be considered technically infeasible, although the possibility of utilizing tempering air to reduce the inlet exhaust temperature, at substantial costs, exists. Therefore, oxidation catalyst is considered technically feasible for installation on the Facility's combustion turbines and will be considered further in Step 4 to evaluate cost effectiveness.

$EM_X^{TM}$/$SCONO_X^{TM}$

The $EM_X^{TM}$/$SCONO_X^{TM}$ catalyst system is a post-combustion technology that utilizes a proprietary oxidation catalyst and absorption technology using a single catalyst (potassium carbonate) for removal of $NO_X$, CO, and VOC without the use of ammonia. As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the $EM_X^{TM}$/$SCONO_X^{TM}$ catalyst system has operated successfully on several smaller, natural gas-fired combined-cycle units, but there are engineering challenges with applying this technology to larger plants with full scale operation.[106] Additionally, the operating range of the catalyst is 300 to 700°F, well below the exhaust temperature for simple cycle combustion turbines.[107] Consequently, it is concluded that $EM_X^{TM}$/$SCONO_X^{TM}$ is not technically feasible for control of VOC emissions from the WCP turbines.

<u>Combustion Process Design and Good Combustion Practices</u>

This represents the base case for design and operation of the simple-cycle combustion turbines.

<u>Summary and Ranking of Remaining VOC Controls – Combustion Turbines (Step 3)</u>

As detailed in the Step 2 analysis for VOC per Section 0 of the application, the only add-on control technically feasible to reduce emissions below the base case (Combustion Process Design and Good Combustion Practices) is oxidation catalyst. As a technically feasible control option, it must be evaluated further in the BACT process.

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[105] U.S. EPA, CATC Fact Sheet for Catalytic Incineration, EPA-452/F-03-018. Available at: www.epa.gov/ttn/catc/dir1/fcataly.pdf

[106] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of $NO_X$, Attachment B pages 14.

[107] U.S. EPA Office of Air and Radition, *Final Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS: Assessment of Non-EGU $NO_X$ Emission Controls, Cost of Controls, and Time for Compliance Final TSD*, August 2016, Appendix A, Page 3-5. Docket ID No. EPA-HQ-OAR-2015-0500.

Evaluation of Most Stringent VOC Controls – Combustion Turbines (Step 4)

Oxidation catalyst is the highest ranking potentially feasible control technology for both natural gas and fuel oil combustion in the turbines. The estimated cost of controlling VOC using oxidation catalyst for the WCP turbines is more than $32K per ton of VOC removed based on the detailed cost analysis provided in Appendix D, developed using the methods outlined by the U.S. EPA in the OAQPS guidance manual.[108] Similar to the technical challenges discussed for SCR for $NO_X$ emissions reductions and use of an oxidation catalyst system for CO emission reductions, estimated costs are high given the high volume of tempering air that would be required to reduce the turbine exhaust temperatures to an acceptable range for operation of an oxidation catalyst. Therefore, WCP concludes that an oxidation catalyst is not cost effective and is not considered BACT for the Facility's turbines

Therefore, combustion process design and good combustion practices represent BACT for the Facility's combustion turbines for VOC.

Selection of Emission Limits and Controls for VOC BACT – Combustion Turbines (Step 5)

The simple cycle combustion turbines are not presently subject to a VOC emission limit and NSPS Subpart KKKK does not establish emission standards for VOC. Accordingly, a BACT floor for VOC does not exist.

As the selected BACT for VOC emissions relies on the combustion process design and good combustion practices, WCP searched U.S. EPA's RBLC database for modifications of similar units at other facilities to determine what has been established as a BACT emission requirement for comparable operations. Numerous entries for natural gas or fuel oil simple cycle combustion turbines are provided in the RBLC summary table in Appendix C of Volume I of the application. Review of the RBLC entries confirms that BACT for VOC emissions are typically combustion process design and good combustion practices for similarly sized simple cycle combustion turbines. "Good combustion practices" typically refers to practices inherent in the routine operation and maintenance of the generating unit, such as automated operating systems and periodic tuning of the turbines.

Once the technology is established, an emission limitation must be proposed, and review of the RBLC entries provides an indication of what has been considered appropriate BACT emission limitations for potentially similar units as those being modified by WCP. As discussed previously, the following qualifying criteria were relied upon in review of the RBLC entries per Appendix C of Volume I of the application to identify potentially comparable units to the WCP turbines:

- Turbine is existing and proposed a modification; exclude units proposed for initial construction;
- Control method does not include control technologies which have been deemed to be infeasible (i.e., Oxidation Catalyst, $EM_X^{TM}$/$SCONO_X^{TM}$);

[108] U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, EPA 452/B-02-001, July 2002. http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf
For more details on the updating of the control cost manual see https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

- Units are similar GE Frame 7 units; and
- Units are utilized for the purposes of power generation and not utilized for other purposes such as compression.

This review has been conducted on a fuel-specific basis, detailed in the following sections.

Selection of Emission Limits for VOC BACT - Natural Gas Firing

Table 5-16 of Volume I of the application includes VOC RBLC database entries for turbine units combusting natural gas which are potentially comparable to the existing units at the WCP facility.

The RBLC entries detailed in Table 5-16 of Volume I of the application includes potential modifications at facilities which were discussed in Section 5.6.6.1 of Volume I of the application. Many of the RBLC database entries have been conservatively included in Table 5-16 of Volume I of the application as they could not be ruled out as units proposed for construction based on information presented in the RBLC database entry alone. As was previously stated, further review of available air permits, permit applications, and other facility documentation proved that many of the turbine units associated with these RBLC database entries are not comparable to the WCP turbine units.

A review of the proposed control technologies for these facilities shows that use of good combustion practices and pipeline quality natural gas are common requirements for VOC BACT. WCP already incorporates the use of good combustion practices and utilizes pipeline quality natural gas as fuel for the existing turbine systems. WCP will continue to utilize those controls as BACT when firing natural gas in the turbines.

As was discussed in detail in Section 5.6.6.1 of Volume I of the application, there are various factors as to why, even with the use of the same control technologies, the emissions limits presented for the facilities in Table 5-16 of Volume 1 of the application are not necessarily directly comparable to the WCP units. Table 4-9 summarizes whether the RBLC listing was actually for a modification of an existing unit, if the turbine involved was a GE Frame 7 turbine, and whether the facilities in Table 5-16 are comparable to the WPC units based on these factors.

**Table 4-9. Unit Comparability for VOC Assessment – Natural Gas Firing**

| Site | Modification? | GE Frame 7 Turbine? | Comparable? | VOC Emission Limit | Averaging Period |
|---|---|---|---|---|---|
| Calcasieu Plant [1] | Increase hours, heat input | Unknown | Yes | N/A – Did not exceed PSD threshold per 2015 PSD permit; ultimately revoked | |
| Emporia Energy Center – GE LM6000PC Units | N/A | No | No | Not Comparable | |
| Emporia Energy Center – GE 7FA | No (New in 2007) Added Tuning Requirements in 2013 | Yes | No (New Unit) Yes (Engine Type) | 3.2 lb/hr (0.0018 lb/MMBtu) | Stack test for compliance at full load |
| Doswell Energy Center [2] | Turbine Relocation | Yes | Yes | 2 ppmvd @ 15% $O_2$ | 1-hr Avg. |
| Puente Power | No - New | Yes | No | Application Revoked | |
| Cameron LNG Facility | No – New | Compressor Turbines | No | Not Comparable | |
| Mustang Station | Increase hours | Yes, 2013 install | Potentially | 2 ppmvd @ 15% $O_2$ | - |
| Ector County Energy Center | No (New in 2014), increased hours in 2020 | Yes | Potentially | 2 ppmvd @ 15% $O_2$ | |

[1] PSD Permit No. PSD-LA-746 issued on December 21, 2011 listed a BACT limit for VOC of 3.0 ppmvd @ 15% $O_2$. However, this permit was requested for revocation in a 2012 Title V Renewal Application. PSD Permit No. PSD-LA-798 was issued on June 1, 2015 and determined that emissions of VOC were not above PSD significant levels; therefore, BACT is not applicable for VOC for the Calcasieu Plant.

[2] The PSD permit for the Doswell Energy Center issued on October 4, 2016 incorporated a VOC BACT limit of 3.57E-04 lb/MMBtu (0.7 lb/hr) for the natural gas fired simple-cycle turbines (CT-2 and CT-3). However, per a revised PSD Permit issued on May 31, 2018, the VOC BACT limit was updated to 2 ppmvd @ 15% $O_2$ (3.3 lb/hr) on a 1-hr averaging basis. This is also consistent with the PSD permit issued on July 30, 2018.

As detailed in Table 4-9, potentially comparable engines combusting natural gas have VOC limits of 3.2 lb/hr, equivalent to 0.0018 lb/MMBtu and 2 ppmvd @ 15% $O_2$. GE's guarantee for the WCP turbines when utilizing good combustion process design, good combustion practices, and pipeline quality natural gas is 1.4 ppmvd at 15% $0_2$; equivalent to 0.00446 lb/MMBtu. Additional research identified a Texas BACT document establishing 2.0 ppmvd as BACT for simple-cycle natural gas combustion turbines.[109] For compliance assurance purposes, **WCP therefore proposes a BACT limit of 2.0 ppmvd at 15% $O_2$, excluding periods of startup and shutdown,** to be demonstrated via stack testing.[110]

[109] Summary spreadsheet *Current BACT for All Combustion Units*, accessed January 27, 2021. https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact-combustion.xlsx

[110] Method 25A for the determination of volatile organic compounds.

Selection of Emission Limits for VOC BACT – Fuel Oil Firing

Table 5-18 of Volume I of the application includes a VOC RBLC database entry for turbine units combusting fuel oil which may be potentially comparable to the existing units at the WCP facility. The only entry was for Wolverine Power.

The Facility did not have a RBLC database entry for VOC associated with the turbine unit for fuel oil firing. However, upon further review of associated permits, permit applications, and other available documentation, it was determined that established BACT limits for VOC existed for the associated turbine units when firing fuel oil. The established BACT limits for VOC were added to this table.

The turbines at the Wolverine Power facility are not subject to a BACT limit for VOC, but rather must comply by utilizing good combustion control technology to mitigate emissions of VOC. Furthermore, plans for the Wolverine Power project were discontinued in 2013 and the facility was never built.

The anticipated BACT for VOC when firing fuel oil would be combustion process design and good combustion practices. Based on BACT limitations for VOC at a similar facility which incorporates the use of dual-fuel fired turbine units, **WCP proposes a BACT limit for VOC of 5.0 ppmvd at 15% $O_2$, excluding periods of startup and shutdown,** with compliance demonstrated via stack testing.[111]

EPD Review – Volatile Organic Carbon (VOC) Emissions

The RBLC database was reviewed, with the intent of finding similarly sized facilities, of similar installation time period, and facilities that had modified the existing process. Also, with a focus of finding similar GE 7FA CTGs in use, at the facility, as possible. The Division has prepared a CO BACT comparison spreadsheet for the similar units using the resources, as discussed in the NOx BACT review.

GA EPD agrees that good combustion practices, pipeline quality natural gas and ULSD fuel represents BACT control technology for VOC. The draft permit restricts fuel usage for natural gas to 12,000 hours of operation during any 12 consecutive months. ULSD is limited to 2,000 hours of operation during any twelve consecutive months.

Of a total of 34 Facility VOC BACT limits, 10 facilities (29.4%) had the 2.0 ppm limit for natural gas despite being new or existing units, therefore this limit is a common choice for the VOC BACT limit for natural gas.

[111] Part 70 Operating Permit Amendment No. 4911-157-0034-V-04-1 issued by Georgia EPD for the Dahlberg Combustion Turbine Electric Generating Plant, effective May 14, 2010. Amendment resulted from a PSD permit application for installation of four simple cycle dual-fuel combustion turbines.

EPD Conclusion – VOC Emissions Control

In comparing the facility to other similarly modified units, the Division agrees with the proposed limit of 2.0 ppm natural gas and 5.0 ppm fuel oil for the combustion turbines (Source Codes: T1-T4), along with good combustion control.

In the Division's review of the RBLC data reveals that the primary control technology for VOC emissions are good combustion and operating practices, and low sulfur fuels such as natural gas. The results are summarized in Table 4-10.

**Table 4-10: VOC BACT Summary for the Combustion Turbine**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| VOC | Good Combustion and Operating Practices, and Low Sulfur Fuels | 2.0 ppm NG<br>5.0 ppm FO | hourly | Performance Test |

## Fuel Oil Storage Tank VOC Assessment

WCP is proposing to construct and operate a new vertical fixed roof tank which will store fuel oil and have a capacity of 2.5 million gallons. Annual emissions resulting from the storage tank have been estimated in Appendix B of Volume I of the application and are not expected to exceed 0.66 tons per year. Given the low magnitude of emissions from the proposed fuel oil storage tank, WCP proposes that the tank be subject to work practice and design standards in lieu of an emission limitation.

Due to the low vapor pressure of fuel oil and minimal estimated annual emissions from the proposed storage tank, a vapor collection and control device for control of emissions will not be utilized. Additionally, carbon adsorption systems are generally not effective for control of low concentrations of VOC which would be generated by a diesel storage tank. The use of floating roofs are also not considered effective for controlling VOC emissions from liquids having low vapor pressures such as diesel.[112] Given the capital costs involved with installation of add-on controls for reduction of less than 1 tpy of emissions, a traditional cost effectiveness analysis would demonstrate a substantial $/ton pollutant removed value, concluding installation of control is not cost effective.

For this small source of VOC emissions, WCP is proposing to incorporate the use of submerged fill systems in the fuel oil storage tank to minimize emissions of VOC resulting from splashing of product loaded. A fill pipe opening will be submerged below the tank's liquid surface level, thereby ensuring that liquid turbulence is mitigated during loading, resulting in minimal emissions into the vapor space above the liquid surface. Another method which WCP will utilize to control emissions from the fuel oil storage tank is to minimize product temperature via the use of light-colored paint for the tank shell and roof. Evaporative losses can be minimized significantly via the appropriate condition and color selection of a storage tank's shell and roof. Evaporative losses have a strong relationship with temperature of liquid product stored; therefore, reducing liquid product temperature can minimize evaporative losses. Solar radiation will increase the temperature of the liquid in a storage tank, but the extent of the temperature increase is determined by the color and condition of the paint on the tank walls and roof. Paints having a low solar absorptance (i.e., light colored tanks) will heat up less than paints with high solar absorptance (i.e., dark colored tanks). White paint, for example, is highly reflective and typically used to minimize the tank's ambient temperature, which, in turn, reduces standing losses.[113]

WCP has determined that BACT for the proposed fuel oil storage tank will be the use of good maintenance practices in accordance with manufacturer specifications, use of a submerged fill pipe for product loading, and selection of tank roof and shell paint colors which have low solar absorptance.

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[112] *Preliminary Determination & Statement of Basis – Outer Continental Shelf Air Permit Modification OCS-EPA-R4012-M1 for Statoil Gulf Services, LLC – Desota Canyon Lease Blocks*, issued by the U.S. EPA Region 4 on July 9, 2014. Discussion related to BACT analysis for storage tanks, Section 6.5 page 29.

[113] Eric Stricklin. "Evaporative Losses From Storage Tanks," Chesapeake Operating, Inc. http://technokontrol.com/pdf/evaporation/evaporation-loss-measurement.pdf. (accessed January 26, 2021).

EPD Review/Conclusion – Fuel Oil Storage Tank VOC Emissions Control

In comparing the facility to other similarly modified units, the Division agrees with the proposed BACT of good maintenance practices in accordance with manufacturer specifications, use of a submerged fill pipe for product loading, and selection of tank roof and shell paint colors which have low solar absorptance.

**Table 4-11: Fuel Oil Storage Tank VOC BACT Summary for the Combustion Turbine**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| VOC | Good Maintenance Practices<br>Submerged fille pipe<br>Low Solar Absorption Paint Colors | - | - | - |

## Combustion Turbines GHG Assessment

This section contains a high-level review of pollutant formation and possible control technologies for the combustion turbine systems. Though the primary GHG emissions from natural gas and fuel oil combustion in the combustion turbine systems are $CO_2$, GHG BACT is discussed separately for $CH_4$ and $N_2O$.

$CO_2$ production from combustion occurs in theory by a reaction between carbon in any fuel and oxygen in the air and proceeds stoichiometrically (for every 12 pounds of carbon burned, 44 pounds of $CO_2$ is emitted).[114] $CH_4$ can be emitted when natural gas and fuel oil are not burned completely in combustion.[115] The last primary component for calculating greenhouse gas emissions (in addition to $CO_2$ and $CH_4$) is $N_2O$. $N_2O$ formation is limited during complete gas and oil combustion situations, as most oxides of nitrogen will tend to oxidize completely to $NO_2$, which is not a GHG.[116]

Please note that the GHG BACT assessment presents a unique challenge with respect to the evaluation of BACT for $CO_2$ and $CH_4$ emissions. The technologies that are most frequently used to control emissions of $CH_4$ in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert $CH_4$ emissions to $CO_2$ emissions. Consequently, the reduction of one GHG (i.e., $CH_4$) results in a simultaneous increase in emissions of another GHG (i.e., $CO_2$).

## Turbine Systems $CO_2$ BACT

The following section presents BACT evaluations for $CO_2$ emissions from the modified turbine systems.

Identification of Potential $CO_2$ Control Technologies (Step 1)

WCP searched for potentially applicable emission control technologies for $CO_2$ from combustion turbines by researching the U.S. EPA control technology database, guidance from U.S. EPA and other sources as described in Section 5.4.1 of this report, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. The RBLC lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These results are summarized in Appendix C of Volume I of the application, detailing emission levels proposed for similar types of emissions units. Based on the RBLC search, no add-on control methods for GHGs were described for any of

[114] *NC Greenhouse Gas (GHG) Inventory Instructions for Voluntary Reporting, November 2009*. Prepared by the North Carolina Division of Air Quality. https://files.nc.gov/ncdeq/Air%20Quality/inventory/forms/GHG_Emission_Inventory_Instructions_Nov2009_Voluntary.pdf

[115] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*. July 1998. Chapter 1, Section 3, *Fuel Oil Combustion*. July 1998.

[116] *NC Greenhouse Gas (GHG) Inventory Instructions for Voluntary Reporting, November 2009*. Prepared by the North Carolina Division of Air Quality. https://files.nc.gov/ncdeq/Air%20Quality/inventory/forms/GHG_Emission_Inventory_Instructions_Nov2009_Voluntary.pdf

the facilities. Many facilities listed a variant of good combustion practices, efficient operation, state-of-the-art technology (for greenfield sites), or low emitting fuels (e.g., pipeline-quality natural gas). Although not mentioned in the RBLC for any sites, energy storage technologies such as batteries are deemed to fall outside the scope of this analysis since they would essentially redefine the source.

WCP used a combination of published resources and general knowledge of industry practices to generate a list of potential controls for $CO_2$ emitted from combustion turbine systems. WCP excluded options such as battery storage or solar power generation from the GHG control technology assessment as they would redefine the business purpose of the proposed projects: WCP Sandersville proposes to operate as a natural gas and fuel oil-fired electric generating facility utilizing simple-cycle combustion turbines, maximizing utilization of the existing assets in a relatively steady-state mode of operation, with normal anticipated variations based on supply needs. U.S. EPA has affirmed that evaluation of control options or lower-emitting GHG processes, such as solar power, that would fundamentally redefine the source is not a requirement of the BACT review in their response to comments on the proposed Palmdale Hybrid Power Project, subsequently upheld in an order denying review of the PSD permit.[117]

The following potential $CO_2$ control strategies were considered as part of this BACT analysis:

- Carbon Capture and Storage (CCS); and
- Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices.

These control technologies are briefly discussed in the following sections. Other $CO_2$ control technologies such as use of alternative fuels (with lower GHG emissions) were not considered because they were not within the scope of the projects. Additionally, natural gas (which has the lowest GHG emissions of any fossil fuel) is the primary fuel that will be utilized by the turbines, with fuel oil usage being limited to 500 hr/yr.

Carbon Capture and Storage

CCS, also known as $CO_2$ sequestration, involves cooling, separation and capture of $CO_2$ emissions from the flue gas prior to being emitted from the stack, compression of the captured $CO_2$, transportation of the compressed $CO_2$ via pipeline, and finally injection and long-term geologic storage of the captured $CO_2$. For CCS to be technically feasible, all three components needed for CCS must be technically feasible; carbon capture and compression, transport, and storage.

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[117] U.S. EPA Environmental Appeals Board decision, *In re: City of Palmdale (Palmdale Hybrid Power Project)*. PSD Appeal No. 11-07, p. 727, decided September 17, 2012, citing .S. EPA Region 9, *Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project* at 3 (Oct. 2011).

> "Finally, we [EPA] note that the incorporation of the solar power generation into the BACT analysis for this facility [Palmdale] does not imply that other sources must necessarily consider alternative scenarios involving renewable energy generation in their BACT analyses. In this particular case, the solar component was a part of the applicant's Project as proposed in its PSD permit application. Therefore, requiring the applicant to utilize, and thus construct, the solar component as a requirement of BACT did not fundamentally redefine the source. EPA has stated that an applicant need not consider control options that would fundamentally redefine the source. However, it is expected that each applicant consider all possible methods to reduce GHG emissions from the source that are within the scope of the proposed project."

The first phase in CCS is to separate and capture the $CO_2$ gas from the exhaust stream, and then to compress the $CO_2$ to a supercritical condition.[118] Since most storage locations for $CO_2$ are greater than 800 meters deep, where the natural temperatures and pressures are greater than the critical point for $CO_2$, to inject $CO_2$ to those depths requires pressurizing the captured $CO_2$ to a supercritical state.

$CO_2$ capture can be performed via solvents or sorbents. The choice of the precise process varies with the properties of the exhaust stream. $CO_2$ separation has been well demonstrated in the oil and gas industries, but the characteristics of those streams are very different from a turbine system exhaust. Most combustion tests and projects have been on exhaust streams from coal combustion, which has more highly concentrated $CO_2$ than exhaust from natural gas and fuel oil combustion, or on natural gas combined-cycle systems. Existing $CO_2$ capture technologies have not been demonstrated in the context of capturing $CO_2$ from simple-cycle combustion turbines, regardless of industry use, as they have higher exit gas temperatures and lower cycle efficiencies, which negatively affects the ability of the CCS systems to control $CO_2$ emissions.[119]

Once separated, $CO_2$ must be compressed to supercritical conditions for transport and storage. There are no technical challenges with compressing $CO_2$ to those levels, but specialized technologies with high operating energy requirements are necessary. The $CO_2$ could be compressed to supercritical either before or after transport.

For phase two, $CO_2$ would be transported to a repository. Transport options could include pipeline or truck. Specialized designs may be required for $CO_2$ pipelines, particularly if supercritical $CO_2$ is being transported. Transport of $CO_2$ by pipeline is a demonstrated technology, but currently most $CO_2$ pipelines are in rural areas. Obtaining right-of-way in developed areas is difficult.

Various $CO_2$ storage methods have been proposed, though only geologic storage is achievable currently. Geologic storage involves injecting $CO_2$ into deep subsurface formations for long-term storage. Typical storage locations would be deep saline aquifers as well as depleted or un-mineable coal seams. Captured $CO_2$ could also potentially be used for enhanced oil recovery via injection into oil fields.

Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices

As the baseline of most analyses, pollutant formation can be most cost-effectively minimized by efficient turbine operation and good combustion, operating, and maintenance practices. One example of an efficient way to generate electricity from a natural gas and fuel oil-fired source is the use of a combined cycle design.[120]

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[118] Supercritical means that the $CO_2$ has properties of both a liquid and a gas. Supercritical $CO_2$ is dense like a liquid but has a viscosity like a gas. For additional details see https://www.netl.doe.gov/coal/carbon-storage/faqs/carbon-storage-faqs

[119] *Carbon Capture Opportunities for Natural Gas Fired Power Systems*, US Department of Energy. accessed January 2021. https://www.energy.gov/sites/prod/files/2017/01/f34/Carbon%20Capture%20Opportunities%20for%20Natural%20Gas%20Fired%20Power%20Systems_0.pdf

[120] http://needtoknow.nas.edu/energy/energy-sources/fossil-fuels/natural-gas/

Within combustion units, operators can control the localized peak combustion temperature and combustion stoichiometry to achieve efficient fuel combustion. Outside of the unit, energy loss can be minimized by providing sufficient insulation to the combustion units and associated duct work.

For the purposes of this GHG control technology assessment, it is important to note that good operating practices includes periodic maintenance by abiding by an operations and maintenance (O&M) plan. Maintaining the combustion units to the designed combustion efficiency and operating parameters is important for energy efficiency related requirements and efficient operation.

Elimination of Technically Infeasible $CO_2$ Control Options – Turbine Systems (Step 2)

Carbon Capture and Storage

CCS involves cooling, separation and capture of $CO_2$ from the flue gas prior to the flue gas being emitted from the stack, compression of the captured $CO_2$, transportation of the compressed $CO_2$ via pipeline, and finally injection and long-term geologic storage of the captured $CO_2$. For CCS to be technically feasible, all three components (carbon capture and compression, transport, and storage) must be technically feasible.

It should be noted that there is little to no research that has been completed on the implementation of CCS systems on simple cycle turbines, nor on turbines that utilize fuel oil. Though the lack of research is due to general industry understanding that it is impossible to utilize a CCS system on a simple cycle turbine, the technical feasibility is still conservatively examined in this section. However, due to this lack of research on simple cycle or fuel-oil fired turbines, the technical feasibility in this section is completed using data collected on CCS systems installed on natural gas combined cycle turbines.

Carbon Capture

In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects).[121] Currently, only two options appear to be feasible for capture of $CO_2$ from the flue gas from the turbine systems: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. In one 2009 M.I.T. study conducted for the Clean Air Task Force, it was noted that "To date, all commercial post-combustion $CO_2$ capture plants use chemical absorption processes with monoethanolamine (MEA)-based solvents."[122]

[121] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, Section III, pages. 27-52. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

[122] Herzog, Meldon, Hatton, Advanced Post-Combustion $CO_2$ Capture, April 2009, page 7. https://sequestration.mit.edu/pdf/Advanced_Post_Combustion_CO2_Capture.pdf

A review of the U.S. Department of Energy's (DoE) National Energy Laboratory's (NETL) research and development awards related to post-combustion capture of $CO_2$ indicates that moving from pilot scale tests at coal-fired power plants to large-scale commercial operations remains a focus.[123] For example, an ongoing project focused on implementation of a membrane capture process at Basin Electric's Dry Fork Station in Wyoming details pilot scale testing completed related to membranes and outlines the study parameters to develop a path to commercialization for a coal-fired utility.[124] Note that the economic feasibility of membrane-technology is presently being studied with regard to retrofitting an existing natural gas combined-cycle combustion turbine operation, Elk Hills Power Plant, located in the middle of the Elk Hills Oil Field, providing options for carbon storage as well as for enhanced oil recovery.[125] Review of the DoE's research projects do not indicate any activity related to fuel oil combustion sources.[126] Although absorption technologies are currently available that may be adaptable to flue gas streams of similar character to the flue gas from the turbine systems, to WCP's knowledge, the technology has never been commercially demonstrated for flue gas control in natural gas fired turbine operations.[127]

Presuming carbon capture is feasible, prior to sending the $CO_2$ stream to the appropriate storage site, it is necessary to compress the $CO_2$ from near atmospheric pressure to pipeline pressure (around 2,000 psia). The compression of the $CO_2$ would require a large auxiliary power load, resulting in additional fuel (and $CO_2$ emissions) to generate the same amount of power.[128] The auxiliary power load could be handled by installation of a separate system to solely support $CO_2$ compression, or alternatively be supported by reducing the available energy for sale, relying on the energy generating systems to instead meet the power needs of the compression system. This is often referred to as an "energy penalty" for operation of the $CO_2$ compression system.

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[123] Website reviewed January 2021: https://netl.doe.gov/node/2476?list=Post-Combustion%20Capture

[124] *Commercial-Scale Front-End Engineering Design Study for Membrane Technology and Research's Membrane Carbon Dioxide Capture Process,* U.S. Department of Energy, National Energy Technology Laboratory, Fact Sheet for Project Number FE0031846, start date October 1, 2019.

https://netl.doe.gov/projects/plp-download.aspx?id=20071&filename=FE0031846_MTR_Polaris%20FEED_tech%20sheet.pdf

[125] *Front-End Engineering Design Study for Retrofit Post-Combustion Carbine Capture on a Natural Gas Combined Cycle Power Plant,* U.S. Department of Energy, National Energy Technology Laboratory, Fact Sheet for Project Number FE0031842, start date October 1, 2019.

https://netl.doe.gov/projects/plp-download.aspx?id=20050&filename=FE0031842_EPRI%20FEED_tech%20sheet.pdf

[126] Website reviewed January 2021: https://netl.doe.gov/node/2476?list=Post-Combustion%20Capture

[127] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for GHG emissions, Attachment B page 62.

[128] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, page 29. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

Carbon Transport

The next step in CCS is the transport of the captured and compressed $CO_2$ to a suitable location for storage. This would typically be via pipeline. Pipeline transport is available and demonstrated, although costly, technology. Short $CO_2$ pipelines have been constructed from power plants to proposed injection wells. However, these pipelines are dedicated use for the power plants and are unavailable for other industrial sites.

Since there are no other $CO_2$ pipelines in the area, WCP would need to construct a $CO_2$ pipeline to a storage location if it were to pursue carbon sequestration as a $CO_2$ control option.[129] While it may be technically feasible to construct a $CO_2$ pipeline, considerations regarding the land use and availability need to be made. For the purposes of this analysis, it is conservatively assumed that a shortest distance pipeline can be built from a potential sequestration site to a potential carbon storage location. Realistically, a longer pipeline would be required to address land use and right-of-way considerations.

Carbon Storage

Capture of the $CO_2$ stream and transport are not sufficient control technologies by themselves but require the additional step of permanent storage. After separation and transport, storage could involve sequestering the $CO_2$ through various means such as enhanced oil recovery, injection into saline aquifers, and sequestration in un-minable coal seams, each of which are discussed as follows:

- Enhanced Oil Recovery (EOR): EOR involves injecting $CO_2$ into a depleted oil field underground, which increases the reservoir pressure, dissolves the $CO_2$ in the crude oil (thus reducing its viscosity) and enables the oil to flow more freely through the formation with the decreased viscosity and increased pressure. A portion of the injected $CO_2$ would flow to the surface with the oil and be captured, separated, and then re-injected. At the end of EOR, the $CO_2$ would be stored in the depleted oil field.
- Saline Aquifers: Deep saline aquifers have the potential to store post-capture $CO_2$ deep underground below impermeable cap rock.
- Un-Mineable Coal Seams: Additional storage is possible by injecting the $CO_2$ into un-mineable coal seams. This has been used successfully to recover coal bed methane. Recovering methane is enhanced by injecting $CO_2$ or nitrogen into the coal bed, which adsorbs onto the coal surface thereby releasing methane.

There are additional methods of sequestration such as direct ocean injection of $CO_2$ and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be technologically available at a small-scale, the limiting factor is the availability of a mechanism for WCP to permanently store the captured $CO_2$.

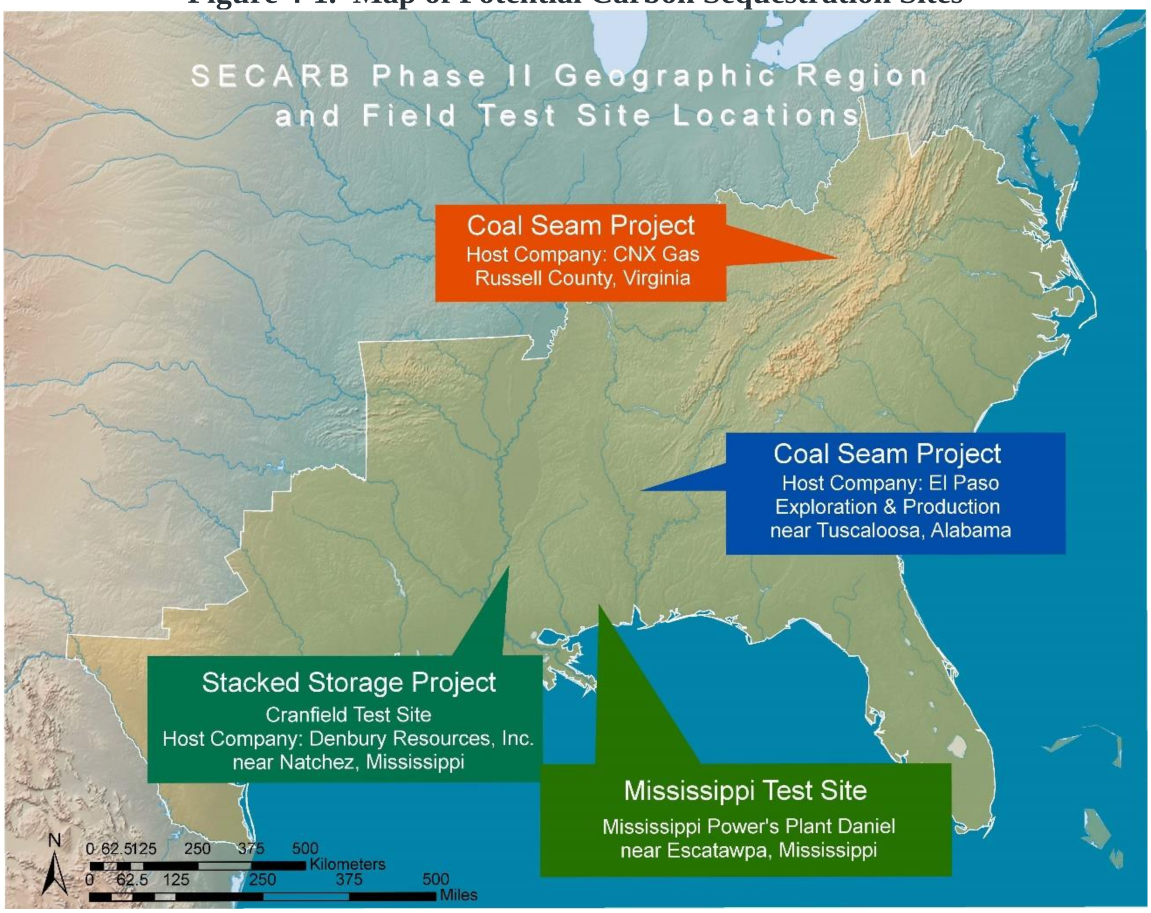
[129] *A Review of the $CO_2$ Pipeline Infrastructure in the U.S.*, National Energy Technology Laboratory, Office of Fossil Energy, U.S. Department of Energy, April 2015. DOE/NETL-2014/1681. https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf

NETL's Carbon Capture and Storage Database provides a summary of potential storage locations.[130] According to the database, the Black Warrior Basin of Alabama is the closest sequestration site where a test well has been drilled. The Black Warrior Basin, located Northeast of Tuscaloosa, Alabama is a pilot-scale Southeast Regional Carbon Sequestration Partnership (SECARB) $CO_2$ sequestration project site that has achieved an injection of 278 tons of $CO_2$ with the potential to sequester 1.12 to 2.32 Gigatonnes (Gt) of $CO_2$.[131] The injection location is a mature coalbed methane reservoir within the Blue Creek Coal Degasification Field in Tuscaloosa County, Alabama.

Figure 4-1 is a map of possible sequestration formations that have gone through SECARB's Phase II Validation program.[132] The Black Warrior Basin, listed as the Coal Seam Project near Tuscaloosa, AL on

Figure 4-11 is the closest pilot or large-scale $CO_2$ sequestration project site to WCP Sandersville and is approximately 246 miles from the Facility.

**Figure 4-1. Map of Potential Carbon Sequestration Sites**




[130]Carbon Capture and Storage Database maintained by the NETL, accessed January 2021 at https://www.netl.doe.gov/coal/carbon-storage/worldwide-ccs-database

[131] *Black Warrior Basin Coal Seam Project,* SECARB. Summary document at http://www.secarbon.org/files/black-warrior-basin.pdf

[132] http://www.secarbon.org/index.php?page_id=8

WCP has concluded that CCS technology is not technically feasible at this time, based on the discussions provided. However, despite the significant technical challenges discussed earlier in implementing CCS technology on turbine systems of this size, WCP is including CCS in Step 3 of this analysis, although realistically technical feasibility is still unlikely.

Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices

One way to efficiently generate electricity from a natural gas or fuel oil fuel source is the use of a combined-cycle turbine design.[133] However, usage of combined-cycle technology is not feasible for this project, as it will remove the turbine's capability to perform its function as a quick starting unit. For the purposes of BACT consideration, combined-cycle and simple-cycle turbines are not considered to be the same source type. Therefore, the use of combined-cycle technology is not being considered as a way of increasing efficiency as it fundamentally changes the scope of the project, and will not be evaluated beyond this step. The EPA Environmental Appeals Board (EAB) affirmed the determination that simple-cycle and combined-cycle technologies are different source types for BACT determination in its response to comments on a PSD permit application for the Pio Pico Energy Center in August 2013.[134]

Efficient turbine operation coupled with good combustion, operating, and maintenance practices are a potential control option for optimizing the fuel efficiency of the combustion turbines. Combustion turbines typically operate in a lean pre-mix mode to ensure an effective staging of air/fuel ratios in the turbine to maximize fuel efficiency and minimize incomplete combustion. Furthermore, the turbine systems are sufficiently automated to ensure optimal fuel combustion and efficient operation leaving virtually no need for operator tuning of these aspects of operation.

Therefore, CCS and efficient turbine operation coupled with good combustion, operating, and maintenance practices are evaluated further for $CO_2$ BACT purposes.

<u>Summary and Ranking of Remaining $CO_2$ Controls (Step 3)</u>

The remaining control methods are listed below, in descending order of the expected $CO_2$ reductions.

- Carbon capture and storage (CCS), 90% reduction[135]
- Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices, reduction efficiency is not applicable.

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[133] http://needtoknow.nas.edu/energy/energy-sources/fossil-fuels/natural-gas/

[134] EAB responded to comments that BACT for a simple-cycle turbine should require a combined-cycle configuration as BACT. In the written response to the appeal, EAB wrote:

"*Mr. Simpson and Sierra Club have not demonstrated that the Region clearly erred in eliminating combined-cycle gas turbines in step 2 of its BACT analysis for greenhouse gases, or that the issue otherwise warrants review or remand. In particular, the Board concludes that the Region did not define "source type" too narrowly in step 2, nor did the Region clearly err when it referenced the power purchase agreement and relateddocuments in its analysis."*

[135] *Estimating Carbon Dioxide Transport and Storage Costs*, National Energy Technology laboratory, U.S. DOE, DOE/NETL-2010/1447, Page 9, March 2010.

Evaluation of Most Stringent $CO_2$ Control Technologies (Step 4)

Carbon Capture and Storage

As the most stringent control option available, CCS would be considered BACT, barring the consideration of its energy, environmental, and/or economic impacts. However, for the reasons outlined in this section, this option should not be relied upon as BACT and the next most stringent alternative should be evaluated.

The use of CCS would be prohibitive to the project, as the cost of installing and maintaining the system will greatly exceed the benefit of any GHG emission reductions the system will offer. The costs associated with the system include capital costs, such as the installation of a pipeline for conveyance and the actual installation of the system, and the operation and maintenance costs of carbon capture, transport, and storage. Detailed cost calculations are provided in Appendix D, with a brief summary herein.

The first capital cost for consideration is the cost associated with the installation of a pipeline from the Sandersville site to the nearest carbon sequestration site. Currently, there exist no carbon storage sites in the state of Georgia, and the site closest to Sandersville is the Black Warrior Basin located near Birmingham, Alabama. If the shortest possible pipeline between these sites were to be installed, 246 miles of pipeline would be installed, crossing from Georgia into Alabama.[136] In addition, one injection well will need to be installed at the basin. Costs involved include an initial site screening, purchasing of injection equipment, well construction, and liability insurance.

As previously discussed, evaluation of costs for CCS systems for natural gas combustion have focused on combined-cycle units. Hence, for purposes of this evaluation, use of cost information related to a natural gas combined-cycle energy facility have been relied upon. Capital costs for carbon capture are calculated based on the difference between a natural gas combined-cycle energy facility with and without capture in terms of $/kW (net). Total plant capital cost for a turbine with no CCS capture is estimated as 780 $/kW, while total plant capital cost for a turbine with CCS is estimated as 1,984 $/kW.[137] As evidenced by these values, the cost of installing a system with CCS capture is greater than double the cost of installing one without. The estimated capital cost for installing the CCS system for the affected turbines by calculating the capital cost for each scenario and taking the difference to calculate the additional cost from the installation of the system.

[136] Distance from the facility to the nearest potential $CO_2$ sequestration facility (Black Warrior Basin) per the Southeast Regional Carbon Sequestration Partnership (SECARB), conservatively assuming the shortest distance as the pipeline route. Note that this site utilized an injection well as part of SECARB's Phase I study, but that injection well has reverted back to its original use for coalbed methane production.

http://secarbon.org/index.php?page_id=8; and

http://secarbon.org/files/black-warrior-basin.pdf

[137] *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, September 2019, Exhibit 5-17, Case B31A Total Plant Cost Details (page 526) and Exhibit 5-31. Case B31B Total Plant Cost Details (page 545).

https://www.netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVol1BitumCoalAndNGtoElectBBRRev4-1_092419.pdf

When the aforementioned costs are summed, the total capital costs for installing a CCS system are greater than $1 billion. This cost alone is clearly prohibitive to the installation of the system but does not yet take operating and maintenance costs into account.

There are several costs related to the ongoing operation and maintenance of a CCS system that are not accounted for in the capital cost, including:

- Operating and maintenance costs for the CCS system such as labor, property taxes, and insurance, as well as costs to purchase the water and chemicals (including an MEA solvent) used in the system itself.
- The pipeline to transport the compressed gas to the storage site has a fixed operation and maintenance costs.138
- The actual storage of the gas at a chosen location requires pore space acquisition, daily expenses, consumables, surface maintenance, and subsurface maintenance.[139]

Based on the calculations completed for these costs, the total annualized cost for operation and maintenance of the CCS system will exceed $235 million. The resulting annualized total capital and operating cost per ton of $CO_2$ controlled is approximately $170 per ton.

The overall costs of installing and operating the CCS system are clearly prohibitive to completing the project, both in terms of absolute costs and cost effectiveness on a $/ton pollutant removed basis. Given the negative economic considerations, as well as the technical challenges associated with implementing CCS on a simple-cycle turbine, it is deemed infeasible and eliminated as a viable option for BACT.

Selection of $CO_2$ BACT (Step 5)

$CO_2$ BACT for these projects includes efficient turbine operation coupled with good combustion, operating, and maintenance practices. As mentioned previously, the resulting BACT standard is an emission limit unless technological or economical limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

BACT determinations for similar simple-cycle generating units, as detailed in the RBLC summary tables in Appendix C denote energy efficiency, good design and good combustion practices as BACT. Post-combustion capture and sequestration of $CO_2$ is not required. BACT limits for natural gas and fuel oil simple-cycle units can be found expressed in terms of lb/MWh, Btu/kWh, or tons, typically with a 12-month rolling total averaging period.

Due to the inherent intermittent usage of the turbine systems, it is most effective to set a BACT limit for tons of $CO_2e$ emitted over a 12-month rolling total averaging period for the units at the WCP Sandersville facility. To calculate the BACT limit, emission factors for fuel combustion were

[138] *Carbon Dioxide Transport and Storage Costs in NETL Studies*, March 2013 DOE/NETL-2013/1614, Exhibit 2.

[139] *Estimating Carbon Dioxide Transport and Storage Costs*, March 2010 National Energy Technology laboratory, U.S. DOE, DOE/NETL-2010/1447, Table 3, March 2010.

http://www.canadiancleanpowercoalition.com/pdf/CTS11%20-%20QGESStransport.pdf based on U.S. EPA default fuel combustion emission factors found in 40 CFR Part 98 Subpart C, Tables C-1 and C-2, converted from units of kg/MMBtu to lb/MMBtu.

The maximum annual operating capacity for each type of fuel was calculated based on the fuel input capacities for each fuel type. The natural gas heat input capacity per turbine is 1,766 MMBtu/hr. Presuming 3,000 hours per year on natural gas per turbine, the facility has a maximum annual operating capacity of 21.2 million MMBtu/yr from natural gas. The fuel oil heat input capacity per turbine is 1,890 MMBtu/hr. With 500 hours per year per turbine for fuel oil combustion, the facility has a maximum annual operating capacity of 3.8 million MMBtu/yr from fuel oil.

As detailed in Appendix C of Volume 1 of the application, multiplying the U.S. EPA emission factors by the maximum annual operating capacity for each type of fuel yields maximum potential emissions of 1,240,760 tons of $CO_2$e/year from natural gas combustion and 309,228 tons of $CO_2$e/year from fuel oil combustion. Summing these together yields potential $CO_2$e emissions of 1,549,988 tpy from the turbine systems combined. As such, **WCP is proposing a BACT limit of 387,497 tpy of $CO_2$e on a 12-month rolling averaging period for each turbine unit**.

Based on a review of the RBLC database, this BACT limit is comparable to other limits that have been established for facilities with similar systems in place. As such, WCP Sandersville believes it is appropriate to comply with PSD requirements.

Compliance with the proposed BACT limit will be demonstrated by monitoring fuel consumption. Specifically, the monthly $CO_2$e emissions will be calculated based on the monthly fuel use, the $CO_2$, $CH_4$, and $N_2O$ emission factors from 40 CFR Part 98 Subpart C, Tables C-1 and C-2, and the current GWPs from Subpart A to 40 CFR 98 (1 for $CO_2$, 25 for $CH_4$, and 298 for $N_2O$). These calculations will be performed on a monthly basis to ensure that the 12-month rolling total tons per year emission limit is not exceeded.

Through this proposed BACT limit, WCP limits the maximum fuel consumption and $CO_2$e emissions, effectively requiring efficient operation at the design heat rate, when operating at 100% load (as inefficient turbine operation would require additional fuel consumption which is undesirable from an operator's perspective).

## Turbine Systems $CH_4$ BACT

$CH_4$ emissions from the natural gas and fuel oil-fired combustion turbines form as a result of incomplete combustion of hydrocarbons present in the natural gas fuel.

### Identification of Potential $CH_4$ Control Technologies (Step 1)

The only available control options for minimizing $CH_4$ emissions from the combustion turbine systems are efficient turbine operation coupled with good combustion, operating, and maintenance practices to minimize unburned fuel. Oxidation catalysts are not considered available for reducing $CH_4$ emissions because oxidizing the very low concentrations of $CH_4$ present in the combustion turbine's exhaust would require much higher temperatures, residence times, and catalyst loadings than those offered commercially for CO oxidation catalysts. For these reasons, catalyst providers do not offer products for reducing $CH_4$ emissions from gas-fired combustion turbines.

Technically Infeasible $CH_4$ Control Options (Step 2)

Efficient turbine operation coupled with good combustion, operating, and maintenance practices are the only technically feasible control options for reducing $CH_4$ emissions from the combustion turbines.

Summary and Ranking of Remaining $CH_4$ Control Technologies (Step 3)

Since efficient turbine operation coupled with good combustion, operating, and maintenance practices are evaluated in the remaining steps of the BACT analysis, no ranking of control options is required.

Evaluation of Most Stringent $CH_4$ Control Technologies (Step 4)

No adverse energy, environment, or economic impacts are associated with efficient turbine operation and good combustion, operating, and maintenance practices for reducing $CH_4$ emissions from the combustion turbine.

Selection of $CH_4$ BACT (Step 5)

Efficient turbine design and good combustion, operating, and maintenance practices are the selected control options for minimizing $CH_4$ emissions from the combustion turbine systems. WCP has determined that a numerical limit for $CH_4$ is unnecessary and that the work practices required for $CO_2$ BACT (i.e., monthly fuel consumption monitoring and emissions calculations), and efficient turbine operation coupled with good combustion, operating, and maintenance practices, are sufficient for $CH_4$ BACT, in addition to the aforementioned $CO_2e$ limit as proposed in the previous paragraph. The $CH_4$ portion of the proposed $CO_2e$ BACT limit will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 25 (per 40 CFR 98 Subpart A, rule effective January 1, 2014).

## Turbine Systems $N_2O$ BACT

For the proposed projects, the contribution of $N_2O$ to the total $CO_2e$ emissions is trivial and therefore should not warrant a detailed BACT review. Nevertheless, the additional information provided supports the rationale that the proposed projects meet BACT for contributions of $N_2O$ to $CO_2e$.

A tradeoff between $NO_X$ and $N_2O$ emissions from the combustion turbines exists when developing a combustion control strategy which influences the BACT selection process. There are five (5) primary pathways of $NO_X$ production in gas-fired combustion turbine combustion processes: thermal $NO_X$, prompt $NO_X$, $NO_X$ from $N_2O$ intermediate reactions, fuel $NO_X$, and $NO_X$ formed through reburning. For turbines using DLN combustors, the $N_2O$ pathway is an important mechanism of $NO_X$ formation. Flame radicals produced in the high temperature and pressure DLN combustion zone react with the $N_2O$ molecule, creating $N_2$ and NO.[140] In premixed gas flames, $N_2O$ is primarily formed in the flame front or oxidation zone. Once formed, the $N_2O$ is readily destroyed due to the relatively high concentration of H radicals, and therefore, the $N_2O$ emissions from premixed gas flames like DLN combustor flames are found experimentally to be very small (generally less than 1 ppm). However, any mechanisms which decrease the H atom concentration in the $N_2O$ formation zone can increase $N_2O$ emissions. These mechanisms include lowering the flame combustion temperature, air-to-fuel staging, and injection of ammonia, urea, or other amine or cyanide species into the exhaust stream which are all common $NO_X$ control measures.[141] Therefore, there is a tradeoff between $NO_X$ and $N_2O$ emissions when developing a combustion control strategy which influences the BACT selection process.

Identification of Potential $N_2O$ Control Technologies (Step 1)

$N_2O$ catalysts are a potential control option, as these have been used in nitric/adipic acid plant applications to minimize $N_2O$ emissions.[142] Through this technology, tail gas from the nitric acid production process is routed to a reactor vessel with a $N_2O$ catalyst followed by ammonia injection and a $NO_X$ catalyst.

Technically Infeasible $N_2O$ Control Options (Step 2)

$N_2O$ catalyst providers do not offer products to control $N_2O$ emissions from gas-fired combustion turbines due to the very low $N_2O$ concentrations present in exhaust streams (approximately 5 ppm).[143] In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) $N_2O$ concentration in the exhaust stream.

With $N_2O$ catalysts eliminated, good combustion practice is the only available control option. Good combustion practices are technically feasible control options for reducing $N_2O$ emissions from the combustion turbines.

Summary and Ranking of Remaining $N_2O$ Control Technologies (Step 3)

Since good combustion practices are evaluated in the remaining steps of the BACT analysis, no ranking of control options is required.

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[140] Angello, L., Electric Power Research Institute, *Fuel Composition Impacts on Combustion Turbine Operability*, March 2006.

[141] American Petroleum Institute, *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*, February 2004.

[142] *$N_20$ Emissions from Adipic Acid and Nitric Acid Production*, written by Heike Mainhardt (ICF Incorporated) and reviewed by Dina Kruger (U.S. EPA). http://www.ipcc-nggip.iges.or.jp/public/gp/bgp/3_2_Adipic_Acid_Nitric_Acid_Production.pdf

[143] *Emissions of Nitrous Oxide from Combustion Sources,* in Progress and Energy and Combustion Science 18(6): pages 529-552 , December 1992, found at: https://www.researchgate.net/publication/223546823_Emissions_of_nitrous_oxide_from_combustion_sources

Evaluation of Most Stringent $N_2O$ Control Technologies (Step 4)

As indicated in U.S. EPA's guidance on GHG BACT, GHG control strategies may have the potential to produce higher criteria pollutants as in the case of the competing $NO_X$ and $N_2O$ combustion control strategies for WCP's combustion turbine systems. In such cases, the guidance suggests that the applicant should consider the effects of increases in emissions of other regulated pollutants that may result from the use of that GHG control strategy, and based on this analysis, the permitting authority can determine whether or not the application of that GHG control strategy is appropriate given the potential increases in other pollutants.[144]

Given the low $N_2O$ emissions relative to $NO_X$ emissions from the combustion turbine systems and U.S. EPA's continued concern over adverse impacts from ozone formation due to $NO_X$ and VOC emissions, WCP does not consider it appropriate to control the combustion processes of the combustion turbine to specifically reduce $N_2O$ emissions due to the counteractive increase in $NO_X$ emissions. Therefore, good combustion practice for the specific purpose of minimizing $N_2O$ formation is eliminated on the basis of adverse criteria pollutant impacts.

Selection of $N_2O$ BACT (Step 5)

Efficient turbine design and general good combustion, operating, and maintenance practices are the selected control options for reducing $N_2O$ emissions from the combustion turbines. WCP has determined that a numerical limit for $N_2O$ emissions is unnecessary and that the work practices required for $CO_2$ BACT (i.e., monthly fuel consumption monitoring and emissions calculations), and efficient turbine operation coupled with good combustion, operating, and maintenance practices, are sufficient for $N_2O$ BACT, in addition to the aforementioned $CO_2e$ limit as proposed in previous paragraph. The $N_2O$ portion of the proposed $CO_2e$ BACT limit will be calculated based on the emission factor from 40 CFR Part 98 Subpart C and the GWP of 298 (per 40 CFR 98 Subpart A, rule effective January 1, 2014).

EPD Review – Greenhouse Gases (GHGs) Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the GHG BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[145]
- Final/Draft Permits and Final/Preliminary Determinations for similar sources

The Division has prepared a GHG BACT comparison spreadsheet for the similar units using the above-mentioned resources.

A comparable facility is Indeck Wharton, L.L.C. that proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will either be the General Electric 7FA (~214 MW each) or the Siemens SGT6-5000F (~227 MW each), operating as peaking units in simple cycle mode. The facility has proposed a limit of 358,529 tpy $CO_2E$ 12-month rolling total. This BACT limit compares to WCP's GHG limit of 387,497 tpy $CO_2E$ 12-month rolling total.

144 *PSD and Title V permitting Guidance for Greenhouse Gases*. March 2011, page 39.

145 http://cfpub1.epa.gov/rblc/htm/bl02.cfm

EPD Conclusion – Greenhouse Gases (GHGs) Control

In comparing the facility to other similarly modified units, the Division agrees with the proposed limit of 387,497 tpy $CO_2$e 12-month rolling total for the combustion turbines (Source Codes: T1-T4), along with good combustion control.

In the Division’s review of the RBLC data reveals that the primary control technology for GHS emissions are good combustion and operating practices, and low sulfur fuels such as natural gas. The results are summarized in Table 4-12.

**Table 4-12: GHG BACT Summary for the Combustion Turbine**

| Pollutant | Control Technology | Proposed BACT Limit | Averaging Time | Compliance Determination Method |
|---|---|---|---|---|
| GHG | Good Combustion and Operating Practices, and Low Sulfur Fuels | 387,497 tpy $CO_2$e 12-month rolling total | hourly | Record of Fuel Usage |

## 5.0 TESTING AND MONITORING REQUIREMENTS

Requirements for $NO_x$

The combustion turbine systems currently employ a continuous emission monitoring system (CEMS) for NOx per the requirements of the Acid Rain Program (ARP), promulgated in 40 CFR Part 75. Per 40 CFR 4340(b)(2)(iv), units operating without water injection that are regulated by 40 CFR Part 75 may rely on the 40 CFR Part 75 Appendix E procedures for documenting ongoing compliance with the NSPS Subpart KKKK NOx standards with approval from the state. The WCP units operate without water injection during natural gas combustion.

Water injection will be required for fuel oil combustion. 40 CFR 60.4335 establishes NOx monitoring options for water injection, including use of a CEM, but does not explicitly state that the Part 75 procedures may be relied upon. However, NSPS Subpart KKKK specific requirements for a CEM are detailed in 40 CFR 60.4345, including an option to rely on a CEM installed and certified per 40 CFR Part 75.32 Therefore, the use of the existing NOx CEMs meeting the requirements of 40 CFR Part 75 Appendix E should be sufficient for NSPS Subpart KKKK NOx ongoing compliance monitoring purposes.

Continuous compliance with the $NO_x$ emission limitations of Subpart KKKK will be demonstrated with a $NO_x$ CEMS in keeping with 40 CFR 60.4335(b)(1), 60.4340(b)(1), and 60.4345. Each $NO_x$ CEMS must be installed and certified according to Performance Specification 2 of 40 CFR Part 60, Appendix B, except that the 7-day calibration drift is to be based on unit operating days, not calendar days.

Four-hour rolling $NO_x$ emission measurements by the $NO_x$ CEMS satisfy the periodic monitoring requirement for the non-NSPS $NO_x$ emission limits. The four-hour rolling $NO_x$ emission measurements will also satisfy the Subpart KKKK $NO_x$ emission limits. Therefore, provided that the four-hour $NO_x$ CEMS average concentrations are less than either 15 ppm (firing natural gas) or 42 ppm (firing fuel oil), the Division concludes that the $NO_x$ CEMS can be used to demonstrate continuous compliance with the Subpart KKKK $NO_x$ emission limits. An excess emissions for NSPS purposes, therefore, will consist of any unit operating period in which the 4-hour rolling average $NO_x$ emission rate exceeds either 15 ppm (firing natural gas) or 42 ppm (firing fuel oil).

To reasonably assure compliance with the BACT $NO_x$ emission limitations, the Permittee must install, calibrate, operate, and maintain a $NO_x$ CEMS for periodic monitoring of $NO_x$ emissions from each combustion turbine.

Sources demonstrating compliance with the NOx emission limits via CEMS are not subject to the requirement to perform initial and annual NOx stack tests of Subpart KKKK.[146] Initial compliance with the applicable NOx emission limits will be demonstrated by comparing the arithmetic average of the NOx emissions measurements taken during the initial RATA to the NOx emission limit under this subpart.[147]

[146] 40 CFR 60.4340(b), 40 CFR 60.4405

[147] 40 CFR 60.4405(c) and (d)

The proposed primary BACT limits of 9.0 ppmvd and 42 ppmvd for natural gas and fuel oil firing, respectively, do not apply during periods of startup/shutdown. Secondary BACT limits are required given that the non-steady state operations during periods of startup and shutdown result in a substantially different NOx emissions profile as the combustion units are not operating in an ideal mode for managing combustion characteristics. WCP therefore proposes a secondary BACT limit per turbine of 152.7 tpy on a rolling 12-month basis to ensure the minimization of emissions during startup/shutdown periods.

WCP will determine and record the mass emission rate (lb/hr) of NOx from each combustion turbine for each hour or portion of each hour of operation. The mass emission rate from each combustion turbine will be calculated by multiplying the total NOx emissions in units of pounds per million Btu, determined in accordance with the procedures of 40 CFR Part 75, Section 3 of Appendix F, by the total heat input for that hour determined in the accordance with the procedures of 40 CFR 75, Section 5.5 of Appendix F.

Requirements for CO

Compliance with the BACT CO emission limitations for each combustion turbine must be demonstrated by an initial performance test using Method 10, the method for compliance determination. For each of the simple-cycle systems (Combustion Turbines CT11, CT12, CT13, and CT14), separate tests must be conducted while burning natural gas and ultra-low sulfur diesel fuel. Periodic testing will be required, on each combustion turbine, no more than 60 months following the previous performance test.

The proposed primary BACT limits of 9.0 ppmvd and 20.0 ppmvd for natural gas and fuel oil firing, respectively, do not apply during periods of startup/shutdown. Secondary BACT limits are required given that the non-steady state operations during periods of startup and shutdown result in a substantially different CO emissions profile as the combustion units are not operating in an ideal mode for managing combustion characteristics. WCP therefore proposes a secondary CO BACT limit per turbine of 70.9 tpy to ensure the minimization of emissions during startup/shutdown periods.

Requirements for $SO_2$

NSPS Subpart KKKK requires the total sulfur content of the fuel to be monitored. However, if a fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb $SO_2$/MMBtu heat input, then the Permittee may elect not to monitor the sulfur content of that fuel. In keeping with the provisions of 40 CFR 60.4365, the Permittee will therefore demonstrate that neither the pipeline quality natural gas nor the ultra-low sulfur diesel fuel contains potential sulfur emissions in excess of 0.060 lb $SO_2$/MMBtu.

The Acid Rain regulations require that $SO_2$ mass emissions from each combustion turbine be measured and recorded. One option for satisfying that requirement is to use applicable procedures specified in Appendix D to 40 CFR Part 75 for estimating hourly $SO_2$ mass emissions. $SO_2$ mass emissions from firing pipeline quality natural gas will be estimated using the regulatory default $SO_2$ emission rate of 0.0006 lb $SO_2$/MMBtu and the applicable quantity of natural gas burned in the combustion turbine. The heat content for the natural gas is 1020 Btu/scf. $SO_2$ mass emissions from Combustion Turbines CT11, CT12, CT13 and CT14 firing ultra-low sulfur diesel fuel will be calculated based on the average sulfur content and heat content of that oil and the quantity of that oil which is burned. The sulfur content and heat content of that oil will be provided by appropriate certifications from the fuel suppliers. The Permittee will also have the flexibility to monitor the sulfur content and heat content of that oil using "as-received" samples instead of fuel-supplier certifications. The Division believes that this method of compliance is acceptable provided that the sulfur content of all oil delivered meets the applicable limit, which is 15 ppm.

Requirements for VOC

Method 25A performance testing will be the compliance determination method for VOC. There is no reliable and readily available method for long-term, continuous monitoring of VOC emissions from the type of fuel-burning equipment proposed by the Permittee. The performance tests for carbon monoxide and volatile organic compounds shall be conducted concurrently.

With the use of good combustion practices, pipeline quality natural gas, and Ultra low Sulfur Distillate (USLD) fuel, the Division concurs, that no monitoring of VOC will be required except for the semi-annual submittal of the percent sulfur in the fuel via a fuel analysis.

Requirements for Particulate Matter and Opacity

Natural gas and USLD fuel are both low-ash fuels. Consequently, the Division believes each simple-cycle system will emit negligible amounts of particulate matter and visible emissions. Each system will be tested while its combustion turbine fires natural gas and also while it fires ultra-low sulfur diesel. Compliance with the particulate matter and visible emissions limits will be determined using Method 5T and Method 9, respectively. Method 9 also will be the basis for periodic monitoring of visible emissions, when the Division deems necessary.

With the use of good combustion practices, pipeline quality natural gas, and USLD fuel, the Division concurs, that no monitoring of $PM_{10}$ will be required except for the semi-annual submittal of the percent sulfur in the fuel via a fuel analysis.

Requirements for GHG

Compliance with the proposed GHG BACT limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with those presented in Table 4-14. The facility will have conditions in the permit that require monthly recordkeeping of natural gas and fuel oil usage in each combustion turbine.

Specifically, the monthly $CO_2e$ emissions will be calculated based on the monthly fuel use, the $CO_2$ emission factor from Appendix G to 40 CFR 75, the $CH_4$ and $N_2O$ emission factors from Subpart C to 40 CFR 98, and the current GWPs from Subpart A to 40 CFR 98 (1 for CO2, 25 for CH4, and 298 for $N_2O$). These calculations will be performed on a monthly basis to ensure that the 12- month rolling total tons per year emission rate does not exceed this limit.

CAM Applicability:

The Combustion Turbines (Source Codes: T1 - T4) are subject to the requirements of compliance assurance monitoring (CAM) as specified in 40 CFR 64. CAM is only applicable to emission units that have potential emissions greater than the major source threshold, located at a major source, use a control device to control a pollutant emitted in an amount greater than the major source threshold for that pollutant, and have a specific emission standard for that pollutant. The Combustion Turbines (Source Codes: T1 - T4) will use a water injection system to control NOx emissions while firing fuel oil. Refer to Section 3.0 “Review of Applicable Rules and Regulations” of this document for more detail on the CAM requirements for Combustion Turbines (Source Codes: T1- T4).

## 6.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed modifications, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class I or Class II area. NAAQS exist for $NO_2$, CO, $PM_{2.5}$, $PM_{10}$, $SO_2$, Ozone ($O_3$), and lead. PSD increments exist for $SO_2$, $NO_2$, and $PM_{10}$.

The proposed project at the WCP triggers PSD review for PM/$PM_{10}$/$PM_{2.5}$, NOx, CO, VOC and GHGs. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for $PM_{10}$, $PM_{2.5}$, CO and $NO_2$. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information packages.

**Modeling Requirements**

The air quality modeling analysis was conducted in accordance with Appendix W of Title 40 of the Code of Federal Regulations (CFR) §51, *Guideline on Air Quality Models*, and Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*.

The proposed project will cause net emission increases of PM/$PM_{10}$/$PM_{2.5}$, NOx, CO, VOC and GHGs that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment. TRS and VOC do not have established PSD modeling significance levels (MSL) (an ambient concentration expressed in either $\mu g/m^3$ or ppm). While TRS does not have established Significant Impact Levels, it does have an ambient monitoring *de minimis* threshold that is concentration-based. Therefore, TRS modeling was conducted to demonstrate that the project impact is below the ambient monitoring *de minimis* concentration. Modeling is not required for VOC emissions; however, the project will likely have no impact on ozone attainment in the area based on data from the monitored levels of ozone in Washington County and the level of emissions

increases that will result from the proposed project. The southeast is generally $NO_X$ limited with respect to ground level ozone formation. VOC/NOx ozone-based impacts are assessed in evaluation of the MERPs.

**Significance Analysis: Ambient Monitoring Requirements and Source Inventories**

Initially, a Significance Analysis is conducted to determine if the PM/$PM_{10}$/$PM_{2.5}$, NOx, CO, VOC and GHGs emissions increases at the WCP would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established Significant Impact Level (SIL). The SIL for the pollutants of concern are summarized in Table 6-1.

If a significant impact (i.e., an ambient impact above the SIL) does not result, no further modeling analyses would be conducted for that pollutant for NAAQS or PSD Increment. If a significant impact does result, further refined modeling would be completed to demonstrate that the proposed project would not cause or contribute to a violation of the NAAQS or consume more than the available Class II Increment.

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 6-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation is required for PM/$PM_{10}$/$PM_{2.5}$, NOx, CO, and GHGs.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the SIL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses. $PM_{2.5}$ does have established SILs per an EPA finalized memo (April 2018) which recommended use of a 24-hr $PM_{2.5}$ SIL of 1.2 ug/m$^3$, and an annual SIL of 0.2 ug/m$^3$. However, the guidance indicated that the permitting authority had the discretion to continue to utilize the previously established annual SIL of 0.3 ug/m$^3$. EPA responded to the existing vacature of the SMCs by indicating that existing background monitors should be sufficient to fulfill the ambient monitoring requirements for $PM_{2.5}$.

**Table 6-1: Summary of Modeling Significance Levels**

| Pollutant | Averaging Period | PSD Significant Impact Level (ug/m$^3$) | PSD Monitoring Deminimis Concentration (ug/m$^3$) |
|---|---|---|---|
| $PM_{2.5}$ | Annual | 0.2 | -- |
| | 24-Hour | 1.2 | -- |
| $PM_{10}$ | Annual | 1 | -- |
| | 24-Hour | 5 | 10 |
| $NO_2$ | Annual | 1 | 14 |
| | 1-Hour | 7.5 | |
| CO | 8-Hour | 500 | 575 |
| | 1-Hour | 2000 | -- |

## NAAQS Analysis

The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the "levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health." Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant." The primary and secondary NAAQS are listed in Table 6-2 below.

**Table 6-2: Summary of National Ambient Air Quality Standards**

| Pollutant | Averaging Period | NAAQS | |
|---|---|---|---|
| | | Primary / Secondary ($ug/m^3$) | Primary / Secondary (ppm) |
| $PM_{10}$ | Annual | *Revoked 12/17/06 | *Revoked 12/17/06 |
| | 24-Hour | 150 / 150 | -- |
| $PM_{2.5}$ | Annual | 15 / 15 | -- |
| | 24-Hour | 35 / 35 | -- |
| $NO_X$ | Annual | 100 / 100 | 0.053 / 0.053 |
| CO | 8-Hour | 10,000 / None | 9 / None |
| | 1-Hour | 40,000 / None | 35 / None |

If the maximum pollutant impact calculated in the Significance Analysis exceeds the SIL at an off-property receptor, a NAAQS analysis is required. The NAAQS analysis would include the potential emissions from all emission units at the WCP, except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations. The emissions modeled for this analysis would reflect the results of the BACT analysis for the modified emission unit. Facility emissions would then be combined with the allowable emissions of sources included in the regional source inventory. The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate compliance. For an annual average NAAQS analysis, the highest modeled concentration among five consecutive years of meteorological data would be assessed, while the highest second-high impact would be assessed for the short-term averaging periods.

**PSD Increment Analysis**

The PSD Increments were established to "prevent deterioration" of air quality in certain areas of the country where air quality was better than the NAAQS. To achieve this goal, U.S. EPA established PSD Increments for certain pollutants. The sum of the PSD Increment concentration and a baseline concentration defines a "reduced" ambient standard, either lower than or equal to the NAAQS that must be met in an attainment area. Significant deterioration is said to have occurred if the change in emissions occurring since the baseline date results in an off-property impact greater than the PSD Increment (i.e., the increased emissions "consume" more that the available PSD Increment).

U.S. EPA has established PSD Increments for $NO_X$, $SO_2$, and $PM_{10}$; no increments have been established for CO or $PM_{2.5}$ (however, $PM_{2.5}$ increments are expected to be added soon). The PSD Increments are further broken into Class I, II, and III Increments. The WCP is located in a Class II area. The PSD Increments are listed in Table 6-3.

**Table 6-3: Summary of PSD Increments**

| Pollutant | Averaging Period | PSD Increment | |
|---|---|---|---|
| | | Class I ($ug/m^3$) | Class II ($ug/m^3$) |
| $PM_{10}$ | Annual | 4 | 17 |
| | 24-Hour | 8 | 30 |
| $NO_X$ | Annual | 2.5 | 25 |

To demonstrate compliance with the PSD Increments, the increment-affecting emissions (i.e., all emissions increases or decreases after the appropriate baseline date) from the facility and those sources in the regional inventory would be modeled to demonstrate compliance with the PSD Class II increment for any pollutant greater than the SIL in the Significance Analysis. For an annual average analysis, the highest incremental impact will be used. For a short-term average analysis, the highest second-high impact will be used.

The determination of whether an emissions change at a given source consumes or expands increment is based on the source classification (major or minor) and the time the change occurs in relation to baseline dates. The major source baseline date for $NO_X$ is February 8, 1988, and the major source baseline for $SO_2$ and $PM_{10}$ is January 5, 1976. Emission changes at major sources that occur after the major source baseline dates affect Increment. In contrast, emission changes at minor sources only affect Increment after the minor source baseline date, which is set at the time when the first PSD application is completed in a given area, usually arranged on a county-by-county basis. The minor source baseline dates have been set for $PM_{10}$ and $SO_2$ as January 30, 1980, and for $NO_2$ as April 12, 1991.

## Modeling Methodology

Details on the dispersion model, including meteorological data, source data, and receptors can be found in EPD's PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix C of this Preliminary Determination and in Volume II of Application No. TV-547905.

## Modeling Results

Tables 6-4 shows that the proposed project will not cause ambient impacts of CO and $PM_{10}$ above the appropriate SIL. Because the emissions increases from the proposed project result in ambient impacts less than the SIL, no further PSD analyses were conducted for these pollutants.

However, maximum modeled ambient impacts were predicted above the SILs for $NO_2$ (1-hour and annual averaging periods) and $PM_{2.5}$ (24-hour and annual averaging periods). Therefore, a Full Impact Analysis was conducted for NOx (1-hour and annual) and $PM_{2.5}$ (24-hour and annual).

**Table 6-4: Class II Significance Analysis Results – Comparison to SILs**

| Criteria Pollutant | Averaging Period | Significant Impact Level | Maximum Projected Concentration* | Receptor UTM Zone: 17 | | Exceeds SIL? | Radius of the SIA |
|---|---|---|---|---|---|---|---|
| | | (µg/m$^3$) | (µg/m$^3$) | Easting (meter) | Northing (meter) | | (km) |
| **$NO_2$** | Annual | 1 | **2.517** | 315,203.2 | 3,663,094.7 | **Yes** | 0.59 |
| | 1-Hour$^+$ | 7.5 | **103.76** | 315,189.4 | 3,662,942.4 | **Yes** | 53.64 |
| **$PM_{10}$** | Annual | 1 | 0.2442 | 315,203.2 | 3,663,133.4 | No | N/A |
| | 24-Hour | 5 | 4.233 | 315,119.7 | 3,663,133.4 | No | N/A |
| **$PM_{2.5}$** | Annual$^\#$ | 0.2 | **0.2597** | 315,203.2 | 3,663,094.7 | **Yes** | 0.36 |
| | 24-Hour$^\#$ | 1.2 | **4.418** | 315,119.7 | 3,663,133.4 | **Yes** | 0.36 |
| **CO** | 1-hour | 2,000 | 106.45 | 315,123.0 | 3,663,140.0 | No | N/A |
| | 8-hour | 500 | 60.00 | 315203.2 | 3,663,094.7 | No | N/A |

* DMU evaluated secondary $PM_{2.5}$ impact estimated with the MERP approach using the $NO_X$ and $SO_2$ emissions at the proposed facility. Worst case determinations were conducted for operating load, fuel oil firing and natural gas firing.

**Significant Impact Area**

For any off-site pollutant impact calculated in the Significance Analysis that exceeds the SIL, a Significant Impact Area (SIA) must be determined. The SIA encompasses a circle centered on the facility being modeled with a radius extending out to the lesser of either: 1) the farthest location where the emissions increase of a pollutant from the proposed project causes a significant ambient impact, or 2) a distance of 50 kilometers. All sources of the pollutants in question within the SIA plus an additional 50 kilometers are assumed to potentially contribute to ground-level concentrations and must be evaluated for possible inclusion in the NAAQS and Increment Analysis. The use of AERMOD is generally appropriate for transport distances of up to 50 km. However, there may be cases where the State believes it's necessary to include a source more than 50 km from the PSD source in the modeling inventory which will be evaluated on a case-by-case determination.

Based on the results of the Significance Analysis, the distance between the facility and the furthest receptor from the facility that showed a modeled concentration exceeding the corresponding SIL was determined to be 53.6 kilometers for the 1-hour $NO_2$. All other distances between the facility and receptors showing a modeled concentration exceeding the corresponding SIP were less than 50 kilometers for NOx and $PM_{2.5}$. Although the extent of significant receptors for various significance analyses for 1-hour $NO_2$ is extensive [e.g. 41 km for normal source operation on fuel oil, out to 50 km in some areas for one startup/shutdown (SUSD) scenario], these large impact areas are influenced by the conservative assumptions thus far being used in the modeling (e.g. all units running on natural gas or fuel oil 24 hours per day 7 days a week, SUSD activities happening every day of every year of the data set – even though those assumptions exceed the desired and requested hourly operational limitations for the emission units). Also, given potential real world plume travel times, lack of wind direction deviation to significant travel distances, etc. it is highly unlikely that WCP would cause or contribute to any violations of the NAAQS at such a large distance. Therefore, the maximum inventory source distance considered was maintained at 50 kilometers from the facility. Regional source inventories for both of these pollutants were prepared for sources located within 50 kilometers of the facility.

**NAAQS and Increment Modeling**

The next step in completing the NAAQS and Increment analyses was the development of a regional source inventory. Nearby sources that have the potential to contribute significantly within the facility's SIA are ideally included in this regional inventory. WCP requested and received an inventory of NAAQS and PSD Increment sources from Georgia EPD. WCP reviewed the data received and calculated the distance from the plant to each facility in the inventory. All sources more than 50 km outside the SIA were excluded.

The distance from the facility of each source listed in the regional inventories was calculated, and all sources located more than 50 kilometers from the mill were excluded from the analysis. Additionally, pursuant to the "20D Rule," facilities outside the SIA were also excluded from the inventory if the entire facility's emissions (expressed in tons per year) were less than 20 times the distance (expressed in kilometers) from the facility to the edge of the SIA. In applying the 20D Rule, facilities in close proximity to each other (within approximately 5 kilometers of each other) were considered as one source. Then, any Increment consumers from the provided inventory were added to the permit application forms or other readily available permitting information.

A detailed explanation of the regional source inventory used in the analysis is included in Volume II of Application No. TV-547905 and the attached modeling report.

**NAAQS Analysis**

In the NAAQS analysis, impacts within the facility's SIA due to the potential emissions from all sources at the facility and those sources included in the regional inventory were calculated. Since the modeled ambient air concentrations only reflect impacts from industrial sources, a "background" concentration was added to the modeled concentrations prior to assessing compliance with the NAAQS.

The results of the NAAQS analysis are shown in Table 6-5. For the short-term averaging periods, the impacts are the highest second-high impacts. For the annual averaging period, the impacts are the highest impact. When the total impact at all significant receptors within the SIA are below the corresponding NAAQS, compliance is demonstrated.

**Table 6-5: NAAQS Analysis Results**

| Pollutant | Averaging Period | UTM East (km) | UTM North (km) | Maximum Impact (ug/m$^3$) | Background (ug/m$^3$) | Total Impact (ug/m$^3$) | NAAQS (ug/m$^3$) | Exceed NAAQS? |
|---|---|---|---|---|---|---|---|---|
| $NO_2$ | 1-Hour NG | 315,234.9 | 3,662,889.9 | 66.902 | 30.3 | 97.202 | 188 | No |
| | 1-Hour FO | 290,689.4 | 3,637,242.4 | 374.482 | 30.3 | **404.782** | 188 | **Yes** |
| $PM_{2.5}$ | Annual NG and FO | 315,203.2 | 3,663,094.7 | 4.088 | 4.5 | 8.588 | 100 | No |

*Data for worst year provided only. Fuel options: Natural Gas (NG) and Fuel Oil (FO).

As indicated in Table 6-5 above, predicted modeled impacts for the 1-hr $NO_2$ NAAQS analysis demonstrated that the WCP will not cause or contribute to any violations of the 1-hr $NO_2$ NAAQS under natural gas option. However, under the fuel oil option, predicted modeled impacts for 5 receptors exceeded the 1-hr $NO_2$ NAAQS analysis. Therefore, a contribution analysis was conducted for the 5 receptors that exceeded the 1-hr $NO_2$ NAAQS for emission sources from WCP and off-site inventory sources for receptors.

## NAAQS Contribution Analysis

**Table 6-6: 1-hour $NO_2$ NAAQS Contribution Analysis (Fuel Oil Operation)**

| Exceedance Receptors | Rank | Scenario | All Modeled Conc. (μg/m³)* | WCP Modeled Conc. (μg/m³) | Receptor UTM (Zone: 17) | |
|---|---|---|---|---|---|---|
| | | | | | Easting (meter) | Northing (meter) |
| 1 | 8th | 100% Load | 374.48189 | 0.00142 | 290,689.4 | 3,637,242.4 |
| | | 4AM Startup | 374.48189 | 0.00142 | | |
| | | 10AM Startup | 374.48189 | 0.00142 | | |
| 2 | | 100% Load | 283.11218 | 0.00234 | 286,689.4 | 3,663,242.4 |
| | | 4AM Startup | 283.11218 | 0.00234 | | |
| | | 10AM Startup | 283.11218 | 0.00234 | | |
| 3 | | 100% Load | 196.31169 | 0.00184 | 301,189.4 | 3,636,742.4 |
| | | 4AM Startup | 196.31169 | 0.00184 | | |
| | | 10AM Startup | 196.31169 | 0.00184 | | |
| 4 | | 100% Load | 195.42920 | 0.00140 | 300,689.4 | 3,636,742.4 |
| | | 4AM Startup | 195.42922 | 0.00142 | | |
| | | 10AM Startup | 195.42920 | 0.00140 | | |
| 5 | | 100% Load | 171.58330 | 0.00162 | 291,189.4 | 3,637,242.4 |
| | | 4AM Startup | 171.58332 | 0.00165 | | |
| | | 10AM Startup | 171.58330 | 0.00162 | | |

* The cutoff threshold for a total 1-hour $NO_2$ impact is 157.7 (= 188 - 30.3) μg/m³ where 30.3 μg/m³ is background concentration. The exceedances occur from 8th rank to 82nd rank, but no exceedances afterwards. This refined modeling demonstrates that WCP will not cause or contribute a significant impact to the NAAQS exceedances at the 1-hour $NO_2$ averaging period.

As shown in Table 6-6, WCP will not cause or contribute to any violations of the 1-hr $NO_2$ NAAQS. While the table above only shows the 8th highest contributions, the MAXDCONT output files in the contribution run folder provided in Appendix E (under $NO_2$, 1-hr, FO) of Volume II of Application No. TV-547905 demonstrate that until modeling exceedances are resolved (83rd high) WCP does not cause or contribute to any of the predicted modeled exceedances.

## Increment Analysis

The modeled impacts from the NAAQS run were evaluated to determine whether compliance with the Increment was demonstrated. The results are presented in Table 6-7.

**Table 6-7: Increment Analysis Results – Class II**

| Pollutant | Averaging Period | UTM East (km) | UTM North (km) | Maximum Impact (ug/m³) | Class II Increment (ug/m³) | Exceed Increment? |
|---|---|---|---|---|---|---|
| $NO_2$ | Annual NG and FO | 315,203.2 | 3,663,094.7 | 4.09 | 25 | No |
| $PM_{2.5}$ | Annual | 690,514 | 3,843,487 | 1.02 | 4 | No |
| | 24-hour | 0.96162 | 315,225.9 | 7.38 | 9 | No |

* Data for worst year provided only. Highest of Fuel Oil (FO) or Natural Gas (NG) for $PM_{2.5}$.

** Highest concentration for annual averaging periods and second highest concentrations for 24-hour averaging periods.

*** DMU evaluated secondary $PM_{2.5}$ impacts with the MERP approach using the $NO_X$ and $SO_2$ emissions at the proposed facility and sources in the regional inventory.

Table 6-7 demonstrates that the impacts are below the corresponding increments for $NO_2$ and $PM_{2.5}$ even with the conservative modeling assumption that all NAAQS sources were Increment sources.

## Ambient Monitoring Requirements

**Table 6-8: Significance Analysis Results – Comparison to Monitoring *De Minimis* Levels**

| Pollutant | Averaging Period | UTM East (km) | UTM North (km) | Monitoring De Minimis Level (ug/m$^3$) | Modeled Maximum Impact (ug/m$^3$) | Significant? |
|---|---|---|---|---|---|---|
| $NO_2$ | Annual | 315,203.2 | 3,663,094.7 | 14 | 2.516 | No |
| $PM_{10}$ | 24-hour | 315,119.7 | 3,663,133.4 | 10 | 4.418 | No |
| CO | 8-hour | 315203.2 | 3,663,094.7 | 575 | 60.000 | No |

Data for worst year provided only

No preconstruction monitoring is required for 8-hour CO, Annual $NO_2$, and 24-hour $PM_{10}$.

The impacts for $NO_2$, $PM_{10}$ and CO quantified in Table 6-4 of the Class I Significance Analysis are compared to the Monitoring *de minimis* concentrations, shown in Table 6-1, to determine if ambient monitoring requirements need to be considered as part of this permit action. Because all maximum modeled impacts are below the corresponding de minimis concentrations, no pre-construction monitoring is required for $NO_2$, $PM_{2.5}$, or CO.

As noted previously, the VOC *de minimis* concentration is mass-based (100 tpy) rather than ambient concentration-based (ppm or µg/m$^3$). Projected VOC emissions increases resulting from the proposed modification is less than 100 tpy.

## Class I Area Analysis

Federal Class I areas are regions of special national or regional value from a natural, scenic, recreational, or historic perspective. Class I areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations. U.S. EPA has established policies and procedures that generally restrict consideration of impacts of a PSD source on Class I Increments to facilities that are located near a federal Class I area. Historically, a distance of 100 km has been used to define "near", but more recently, a distance of 200 kilometers has been used for all facilities that do not combust coal.

The nearest Class I Area to the facility, Okefenokee Wilderness, is 234 kilometers away. Six Class I areas exist within a 300 km range from the WPC facility: Okefenokee Wilderness (GA), Wolf Island Wilderness (GA), Cohutta Wilderness (GA), Shining Rock Wilderness (NC), Joyce Kilmer (NC), and Great Smoky Mountains National Park (TN). The USDA Forest Service, U.S. Fish and Wildlife Service (FWS), and the National Park Service are the designated Federal Land Managers (FLMs) responsible for oversight of all six of these Class I areas.

**Table 6-9: Project Impacts and Significant Impact Levels (Class I Areas)**

| Criteria Pollutant | Averaging Period | Significance Level | Maximum Projected Concentration* | Receptor UTM Zone: 16 | | Exceeds SIL? |
|---|---|---|---|---|---|---|
| | | (μg/m$^3$) | (μg/m$^3$) | Easting (meter) | Northing (meter) | |
| **$NO_2$** | Annual | 0.1 | 0.0148 | 364,896.6 | 3,657,852.3 | No |
| **$PM_{10}$** | Annual | 0.2 | 0.0108 | 364,397.4 | 3,657,387.0 | No |
| | 24-Hour | 0.3 | 0.0311 | 299,642.2 | 3,615,722.7 | No |
| **$PM_{2.5}$** | Annual | 0.05 | 0.01111 | 364,397.4 | 3,654,387.0 | No |
| | 24-Hour | 0.27 | 0.0415 | 299,642.2 | 3,615,722.7 | No |

* Highest concentration over all averaging period. Worst case of FO or NG.

## 7.0 ADDITIONAL IMPACT ANALYSES

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of a modification to the facility and an analysis of the air quality impact projected for the area as a result of the general commercial, residential, and other growth associated with the proposed project.

Soils and Vegetation

The effect of the proposed project's CO, NOx, $PM_{10}$ and $PM_{2.5}$ emissions increases on local soils and vegetation is addressed through comparison of modeled impacts to the secondary NAAQS and other relevant screening criteria that have been developed by the U.S. EPA to provide protection for public welfare, including protection against decreased visibility, damage to animals, crops, vegetation and buildings.[148]

Two comparisons were used to address potential soil and vegetation impacts. First, the significance results for modeled criteria pollutants that were below the SIL ($PM_{10}$ and CO) and the NAAQS modeling results for $PM_{2.5}$ and NOx were assessed against the secondary NAAQS standards, which provide protection for public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. Second, modeled impacts for air toxics impacts were compared against conservative screening levels provided by the EPA specifically to address potential soil and vegetation impacts.[149]As shown in Table 7-1, the impacts for each pollutant are below the applicable secondary NAAQS or the EPA screening levels. Thus, there are no adverse impacts expected on soils or vegetation as a result of the proposed project.

[148] U.S. EPA, A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals (EPA 450/2-81-078), 1980.

[149] U.S. EPA, A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA 450/2-81-078), 1981.

**Table 7-1. Soil and Vegetation Impacts**

| Pollutant | Averaging Period | Total Concentration[1] (μg/m³) | Vegetation Sensitivity[2] Sensitive (μg/m³) | Intermediate (μg/m³) | Resistant (μg/m³) | Secondary NAAQS (μg/m³) | Minimum Threshold (μg/m³) | Threshold Exceeded? |
|---|---|---|---|---|---|---|---|---|
| $NO_2$ | 4-Hour | - | 3,760 | 9,400 | 16,920 | N/A | 3,760 | No |
| | 8-Hour | - | 3,760 | 7,520 | 15,040 | N/A | 3,760 | No |
| | 1-Month | - | - | 564 | - | N/A | 564 | No |
| | Annual | 8.34 | - | 94 | - | | 94 | No |
| $PM_{10}$ | 24-hour | 4.23 | - | - | - | 150 | 150 | No |
| | Annual | 0.24 | - | - | - | 50 | 50 | No |
| $PM_{2.5}$ | 24-hour | 22.95 | - | - | - | 35 | 35 | No |
| | Annual | 8.80 | - | - | - | 15 | 15 | No |
| $SO_2$[3] | 1-hour | - | 917 | - | - | N/A | 917 | No |
| | 3-hour | - | 786 | 2,096 | 13,100 | 1,300 | 786 | No |
| | Annual | - | - | 18 | - | N/A | 18 | No |
| CO[3] | 1-wk | - | 1,800,000 | - | 18,000,000 | N/A | 1,800,000 | No |
| $H_2S$[3] | 4-hour | - | 28,000 | - | 560,000 | N/A | 28,000 | No |
| Ethylene[3] | 3-hour | - | - | 47 | - | N/A | 47 | No |
| | 24-hour | - | - | 1.2 | - | N/A | 1.2 | No |
| Fluorine[3] | 10-Days | - | - | 0.5 | - | N/A | 0.5 | No |
| Beryllium[3] | 1-Month | - | - | 0.01 | - | N/A | 0.01 | No |
| Lead[3] | 3-Months | - | - | 1.5 | - | 0.15 | 0.15 | No |

1. Results from the $PM_{10}$ (24-hour and annual) SIL runs were used since a NAAQS analysis was not required.
2. Screening concentrations based on Table 3.1 in "*A Screening Procedure for Impact of Air Pollution Sources on Plants, Soil and Animals*" , EPA, December 12, 1980. Minimum values noted if range listed.
3. Modeling was not required for $SO_2$, CO, $H_2S$, ethylene, fluorine, beryllium, and lead for this project. Hence, compliance with these limits is inherent.

## Growth

The changes proposed to WPC will have little effect on growth, jobs, or construction.

## Visibility

Visibility impairment is any perceptible change in visibility (visual range, contrast, atmospheric color, etc.) from that which would have existed under natural conditions. Poor visibility is caused when fine solid or liquid particles, usually in the form of volatile organics, nitrogen oxides, or sulfur oxides, absorb or scatter light. This light scattering or absorption actually reduces the amount of light received from viewed objects and scatters ambient light in the line of sight. This scattered ambient light appears as haze.

Another form of visibility impairment in the form of plume blight occurs when particles and light-absorbing gases are confined to a single elevated haze layer or coherent plume. Plume blight, a white, gray, or brown plume clearly visible against a background sky or other dark object, usually can be traced to a single source such as a smoke stack.

Georgia's SIP and Georgia *Rules for Air Quality Control* provide no specific prohibitions against visibility impairment other than regulations limiting source opacity and protecting visibility at federally protected Class I areas. To otherwise demonstrate that visibility impairment will not result from continued operation of the mill, the VISCREEN model was used to assess potential impacts on ambient visibility at so-called "sensitive receptors" within the SIA of WCP.

WCP determined the 4 nearest areas of interest to the facility to be (also shown in Figure 5-1 of Volume II of Application No. TV-547905):

- Sandersville/Kaolin Airport – approximately 18 km to the southeast;
- Hamburg State Park – approximately 20 km to the northeast;
- Baldwin State Forest – approximately 21 km to the west-southwest; and
- Baldwin County Airport – approximately 24 km to the west-northwest.

Since there is no ambient visibility protection standard for Class II areas, this analysis is presented for informational purposes only and predicted impacts in excess of screening criteria are not considered "adverse impacts" nor cause further refined analyses to be conducted.

The primary variables that affect whether a plume is visible or not at a certain location are (1) quantity of emissions, (2) types of emissions, (3) relative location of source and observer, and (4) the background visibility range. For this exhaust plume visibility analysis, a Level-1 visibility analysis was performed using the latest version of the EPA VISCREEN model according to the guidelines published in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA-450/4-88-015). The VISCREEN model is designed specifically to determine whether a plume from a facility may be visible from a given vantage point. VISCREEN performs visibility calculations for two assumed plume- viewing backgrounds (horizon sky and a dark terrain object). The model assumes that the terrain object is perfectly black and located adjacent to the plume on the side of the centerline opposite the observer.

In the visibility analysis, the total project $NO_X$ and $PM_{10}$ emissions increases were modeled using the VISCREEN plume visibility model to determine the impacts. For both views inside and outside the Class II area, calculations are performed by the model for the two assumed plume-viewing backgrounds. The VISCREEN model output shows separate tables for inside and outside the Class II area. Each table contains several variables: theta, azi, distance, alpha, critical and actual plume delta E, and critical and actual plume contrast. These variables are defined as:

1. *Theta* – Scattering angle (the angle between direction solar radiation and the line of sight). If the observer is looking directly at the sun, theta equals zero degrees. If the observer is looking away from the sun, theta equals 180 degrees.

2. *Azi* – The azimuthal angle between the line connecting the observer and the line of sight.

3. *Alpha* – The vertical angle between the line of sight and the plume centerline.

4. *delta E* – Used to characterize the perceptibility of a plume on the basis of the color difference between the plume and a viewing background. A delta E of less than 2.0 signifies that the plume is not perceptible.

5. *Contrast* – The contrast at a given wavelength of two colored objects such as plume/sky or plume/terrain.

The analysis is generally considered satisfactory if *delta E* and *Contrast* are less than critical values of 2.0 and 0.05, respectively, both of which are Class I, not Class II, area thresholds. A Level 2 analysis was performed for this project for the Class II visibility areas of interest.

A Level II analysis refines selected Level I input parameters by using representative wind speed and atmospheric stability conditions in the region encompassing both emission source and the sensitive receptor. In contrast, the Level I analysis assumed worst-case parameters (Pasquill-Gifford stability class F and wind speed of 1.0 meters per second) that are not necessarily indicative of local weather patterns that affect visibility when winds blow emission from the WCP toward each of these sensitive receptors. For the Level II analysis, the representative meteorological conditions were determined by creating a joint frequency distribution of atmospheric stability and wind speeds during daylight hours (i.e., 7 am to 6 pm) for the 2015-2019 made from observations at Macon, Georgia. This analysis indicated the combination of atmospheric stability and wind speed conditions at each sensitive receptor that is most likely to occur when the wind direction is such that plume impairment would potentially occur.

As an additional refinement to the Level II analysis, the NOx emission rate was scaled by 75 percent following the Ambient Ration Method to account for the conversion of NOx to $NO_2$ in the atmosphere, since the latter is the specific visibility-impairing species. All other parameters were input as Level I default options. A background visual range of 25 kilometers was used for WCP.

**Table 7-2a. Level 2 VISCREEN Results-Sandersville/Kaolin Airport**

| Background | Theta | Azi | Distance | Alpha | Delta E | | Contrast | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Crit | Plume | Crit | Plume |
| SKY | 10 | 122 | 21 | 46 | 2.0 | 0.734 | 0.05 | -0.001 |
| | 140 | 122 | 21 | 46 | 2.0 | 0.247 | 0.05 | -0.004 |
| TERRAIN | 10 | 84 | 18 | 84 | 2.0 | 0.246 | 0.05 | 0.003 |
| | 140 | 84 | 18 | 84 | 2.0 | 0.071 | 0.05 | 0.002 |

**Table 7-2b. Level 2 VISCREEN Results-Hamburg State Park**

| Background | Theta | Azi | Distance | Alpha | Delta E | | Contrast | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Crit | Plume | Crit | Plume |
| SKY | 10 | 84 | 20.5 | 84 | 2.0 | 0.272 | 0.05 | 0.000 |
| | 140 | 84 | 20.5 | 84 | 2.0 | 0.093 | 0.05 | -0.001 |
| TERRAIN | 10 | 84 | 20.5 | 84 | 2.0 | 0.079 | 0.05 | 0.001 |
| | 140 | 84 | 20.5 | 84 | 2.0 | 0.023 | 0.05 | 0.001 |

**Table 7-2c. Level 2 VISCREEN Results-Baldwin State Forest**

| Background | Theta | Azi | Distance | Alpha | Delta E | | Contrast | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Crit | Plume | Crit | Plume |
| SKY | 10 | 118 | 24.5 | 51 | 2.0 | 0.746 | 0.05 | -0.001 |
| | 140 | 118 | 24.5 | 51 | 2.0 | 0.250 | 0.05 | -0.004 |
| TERRAIN | 10 | 84 | 21.5 | 84 | 2.0 | 0.226 | 0.05 | 0.003 |
| | 140 | 84 | 21.5 | 84 | 2.0 | 0.067 | 0.05 | 0.002 |

**Table 7-2d. Level 2 VISCREEN Results-Baldwin County Airport**

| Background | Theta | Azi | Distance | Alpha | Delta E | | Contrast | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Crit | Plume | Crit | Plume |
| SKY | 10 | 84 | 24 | 84 | 2.0 | 0.088 | 0.05 | 0.000 |
| | 140 | 84 | 24 | 84 | 2.0 | 0.030 | 0.05 | 0.000 |
| TERRAIN | 10 | 84 | 24 | 84 | 2.0 | 0.022 | 0.05 | 0.000 |
| | 140 | 84 | 24 | 84 | 2.0 | 0.007 | 0.05 | 0.000 |

The results of the Level II VISCREEN analysis show that the screening criteria are not exceeded at any of the sensitive receptors when evaluated using the Level II input parameters. Therefore, the proposed modifications to facility are not anticipated to cause adverse impacts on visibility at the sensitive receptors in the area surrounding the plant.

Moreover, an analysis of the Class II increment inventory at the WCP indicates that, since 1975, decreases in actual emissions of visibility-affecting pollutants from the facility far exceed any corresponding increases in potential emissions of these pollutants. Because the perception of industrial plumes has not been an issue in the past, this indicates there is little reason to expect visible industrial plumes from this site will be a substantial future issue.

## Georgia Toxic Air Pollutant Modeling Analysis

Georgia EPD regulates the emissions of toxic air pollutant (TAP) emissions through a program covered by the provisions of *Georgia Rules for Air Quality Control*, 391-3-1-.02(2)(a)3.(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the Georgia EPD's review of TAP emissions as part of air permit reviews are contained in the agency's "*Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*."

## Selection of Toxic Air Pollutants for Modeling

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration (AAC) values. The TAP evaluated are restricted to those that may increase due to the proposed project. Thus, the TAP analysis would generally be an assessment of off-property impacts due to facility-wide emissions of any TAP emitted by a facility. To conduct a facility-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the facility is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the nature of the natural gas and fuel oil fed to the combustion sources, and the fact that there are complex chemical reactions and combustion of fuel taking place in some. The vast majority of compounds potentially emitted however are emitted in only trace amounts that are not reasonably quantifiable.

For each TAP identified for further analysis, both the short-term and long-term AAC were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 of Georgia EPD's *Guideline* contains a flow chart of the process for determining long-term and short-term ambient thresholds. WCP referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AAC (i.e., 24-hour or 15-minute). The AACs were verified by the EPD.

## **<u>Determination of Toxic Air Pollutant Impact</u>**

The Georgia EPD *Guideline* recommends a tiered approach to model TAP impacts, beginning with screening analyses using SCREEN3, followed by refined modeling, if necessary, with ISCST3 or ISCLT3. For the refined modeling completed, the infrastructure setup for the SIA analyses was relied upon with appropriate sources added for the TAP modeling. Note that per the Georgia EPD's *Guideline*, downwash was not considered in the TAP assessment.

### **<u>Initial Screening Analysis Technique</u>**

Generally, an initial screening analysis is performed in which the total TAP emission rate is modeled from the stack with the lowest effective release height to obtain the maximum ground level concentration (MGLC). Note the MGLC could occur within the facility boundary for this evaluation method. The individual MGLC is obtained and compared to the smallest AAC. Due to the likelihood that this screening would result in the need for further analysis for most TAP, the analyses were initiated with the secondary screening technique.

Table 7-3 summarizes the AAC levels and MGLCs of the eleven TAPs. The maximum 15-minute impact is based on the maximum 1-hour modeled impact multiplied by a factor of 1.32. As shown in Table 7-3, the modeled MGLCs for all eleven TAPs are below their respective AAC levels.

**Table 7-3. Modeled MGLCs and the respective AACs.**

| TAP | Averaging Period | AAC ($\mu g/m^3$) | Max Modeled Conc. ($\mu g/m^3$) | Receptor UTM Zone: | |
|---|---|---|---|---|---|
| | | | | Easting (meter) | Northing (meter) |
| Acrolein | Annual | 0.02 | 0.00002 | 315,342.0 | 3,663,223.2 |
| | 15-Minute | 23 | 0.00372 | 312,444.3 | 3,662,591.0 |
| Arsenic | Annual | 0.000233 | 0.00004 | 315,352.4 | 3,663245.9 |
| | 15-Minute | 0.2 | 0.00688 | 312,444.3 | 3,662,591.1 |
| Benzene | Annual | 0.13 | 0.0111 | 315,044.3 | 3,663,391.1 |
| | 15-Minute | 1600 | 0.245 | 315,044.3 | 3,663,391.1 |
| Beryllium | 15-Minute | 0.5 | 0.000198 | 312,444.3 | 3,662,591.1 |
| | Annual | 0.004 | <1.00E-05 | 315,325.4 | 3,663,245.9 |
| 1,3-Butadiene | Annual | 0.03 | 0.00005 | 315,352.4 | 3,663,245.0 |
| | 15-Minute | 1100 | 0.01 | 312,444.3 | 3,662,591.1 |
| Cadmium | Annual | 0.00556 | 0.00004 | 315,203.2 | 3,663,094.7 |
| | 15-Minute | 30 | 0.00301 | 312,444.3 | 3,662,591.1 |
| Formaldehyde | 15-Minute | 245 | 0.416 | 312,444.3 | 3,662,591.1 |
| | Annual | 1.1 | 0.00381 | 315,362.8 | 3,663,268.7 |
| Lead | 24-Hour | 0.00092 | 0.00092 | 313,644.3 | 3,658,691.1 |
| Manganese | Annual | 0.05 | 0.00275 | 315,352.4 | 3,663,245.9 |
| | 15-Minute | 500 | 0.493 | 312,444.3 | 3,662,591.1 |
| Selenium | 24-Hour | 0.48 | 0.00164 | 313,644.3 | 3,658,691.1 |
| Sulfuric Acid | 24-Hour | 2.4 | 0.18 | 315,119.70 | 3,663,133.4 |
| | 15-Minute | 300 | 0.57 | 315,123.00 | 3,663,140.6 |

# 8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 4911-303-0039-V-08-1.

Section 1.0: Facility Description

1.3 Process Description of Modification

WCP is proposing the addition of fuel oil combustion capability for all existing facility turbines to enhance fuel resiliency given increased reliance within the utilities and industrial sectors on natural gas for energy generation. The project includes the modification of the four existing simple-cycle turbines to allow combustion of either natural gas or fuel oil and the installation of a fuel oil storage tank.

Section 2.0: Requirements Pertaining to the Entire Facility

Modified Condition 2.1 containing a facility wide NOx limit of 250 tons/yr for PSD avoidance will no longer apply after the modification is complete and BACT is implemented.

Section 3.0: Requirements for Emission Units

Added the Fuel Oil Storage tank to this table although no permit conditions were modified or added. It is also included in Attachment B of the permit amendment. NSPS KKKK and the water injection controls were also added to the table.

Modified Condition 3.2.3 requiring only natural gas to be burned in the combustion turbines will no longer apply after the modification is complete and BACT in implemented.

New Condition 3.2.4 was added to allow the combustion of natural gas or ULSD in the combustion turbines.

New Condition 3.2.5 was added to limit the hours of operation while firing natural gas to 12,000 hours during any twelve consecutive month period for the total of the four combustion turbines.

New Condition 3.2.6 was added to limit the hours of operation while firing fuel oil to 2,000 hours during any twelve consecutive month period for the total of the four combustion turbines.

Modified Condition 3.3.1 requiring compliance with NSPS Subpart GG will no longer apply after the modification is complete and each combustion turbine is subject to NSPS KKKK.

Modified Condition 3.3.3 with the NOx emission limits for NSPS Subpart GG will no longer apply after the modification is complete and each combustion turbines is subject to NSPS KKKK.

Modified Condition 3.3.4 with fuel sulfur limits for NSPS Subpart GG will no longer apply after the modification is complete and each combustion turbines is subject to NSPS KKKK.

New Condition 3.3.6 requires compliance with NSPS KKKK following completion of the modification for each combustion turbine.

New Condition 3.3.7 contains all the BACT limits for NOx, CO, Filterable PM/ and Total $PM_{10}$/$PM_{2.5}$, VOC and Greenhouse Gases.

New Condition 3.3.8 contains the NSPS KKKK sulfur in fuel limit.

New Condition 3.3.9 requires the operation of BACT for NOx while burning natural gas.

New Condition 3.3.10 requires the operation of BACT for NOx while burning fuel oil.

## Section 4.0: Requirements for Testing

Modified Condition 4.1.3 was modified to ensure correct testing methods were included.

New Condition 4.2.1 was added to state the NOx testing requirements for meeting the BACT limits.

New Condition 4.2.2 was added to state the VOC, CO and PM testing requirements for meeting the BACT limits.

## Section 5.0: Requirements for Monitoring

Modified Condition 5.2.1 was modified to remove the NSPS Subpart GG reference in the citation and replace it with a reference to NSPS Subpart KKKK.

Modified Condition 5.2.3 requiring monitoring for sulfur for NSPS Subpart GG will no longer be applicable after the modification and NSPS KKKK is applicable.

Modified Condition 5.2.5 requiring one-hour average NOx concentration measure by the CEMS was modified to clarify requirement and to change reference from NSPS GG to NSPS KKKK.

New Condition 5.2.6 clarifies monitoring for hours of operation (including Condition 5.2.2), fuel usage and electrical output.

New Condition 5.2.7 monitoring for ULSD fuel sulfur content – fuel oil receipts.

## Section 6.0: Other Recordkeeping and Reporting Requirements

Modified Condition 6.1.7a.i.for excess NOx emissions applicable to NSPS GG will no longer be applicable once the modification is complete for each combustion turbine and NSPS KKKK applies.

New Condition 6.1.7a.ii. added for excess NOx emissions applicable to NSPS KKKK once modifications are complete on each combustion turbine.

New Condition 6.1.7a.iii. added for excess NOx emissions applicable to NSPS KKKK during operations below 75% load.

New Condition 6.1.7a.iv added for excess $SO_2$ emissions applicable to NSPS KKKK once modifications are complete on each combustion turbine.

Modified Condition 6.1.7b.i. for exceedance of facility wide 250 tons NOx limit will no longer be applicable after the modifications are complete and BACT is implemented.

New Conditions 6.1.7b.iii through 6.1.7.ix will become applicable as the modifications are complete to each combustion turbine.

New Condition 6.1.7b.iii for ULSD fuel limit exceedance.

New Condition 6.1.7b.iv for natural gas operation for the total of four turbines over 12,000 hours per twelve consecutive month period.

New Condition 6.1.7b.v for fuel oil operation for the total of four turbines over 2,000 hours per twelve consecutive month period.

New Condition 6.1.7b.vi for any twelve consecutive month period the NOx emissions exceed 152.7 ton from any combustion turbine.

New Condition 6.1.7b.vii for any twelve consecutive month period the CO emissions exceed 70.9 tons from any combustion turbine.

New Condition 6.1.7b.viii for any twelve consecutive month period the CO2e emissions exceed 387,497 tons from any combustion turbine.

New Condition 6.1.7b.ix for any four-hour tolling average period, excluding startup and shutdown that NOx emissions exceed 9.0 ppmvd at 15% oxygen while firing natural gas and 42.0 ppmvd at 15% oxygen while firing fuel oil from each combustion turbine.

Modified Condition 6.1.7d.iii requiring facility wide monthly NOx emissions records submittal will no longer apply after the modifications are complete.

Modified Condition 6.1.7d.iv requiring facility wide annual NOx emissions records submittal will no longer apply after the modifications are complete.

Modified Condition 6.2.3 was modified to reference New Condition 5.2.6.

Modified Condition 6.2.4 for facility wide monthly NOx emissions calculations will no longer apply after the modifications are complete.

Modified Condition 6.2.5 for facility wide annual NOx emissions calculations will no longer apply after the modifications are complete.

Modified Condition 6.2.7 for records of natural gas specification in Condition 5.2.3 will no longer apply after the modifications are complete.

Modified Condition 6.2.8 for sulfur content of natural gas submittal was modified to reference NSPS KKKK.

New Condition 6.2.10 requires twelve consecutive month rolling total calculations and recordkeeping for NOx emissions from each combustion turbine.

New Condition 6.2.11 requires the records of startups and shutdowns.

New Condition 6.2.12 requires calculation and record of the twelve consecutive month rolling total operating time for each turbine while firing natural gas.

New Condition 6.2.13 requires calculation and record of the twelve consecutive month rolling total operating time spent in startup and shutdown mode for each turbine while firing natural gas.

New Condition 6.2.14 requires calculation and record of the twelve consecutive month rolling total operating time for each turbine while firing fuel oil.

New Condition 6.2.15 requires calculation and record of the twelve consecutive month rolling total operating time spent in startup and shutdown mode for each turbine while firing fuel oil.

New Condition 6.2.16 requires the submittal of semiannual analysis of ULSD fuel by the supplier or current, valid purchase contract, tariff sheet or transportation contract for the fuel oil.

New Condition 6.2.17 requires records of quantity of natural gas burned monthly in the combustion turbines.

New Condition 6.2.18 requires records of the quantity of ULSD burned monthly in the combustion turbines.

New Condition 6.2.19 requires the submittal of a CO Mass Emissions Monitoring, Record Keeping and Reporting Plan.

New Conditions 6.2.20 and 6.2.21 require the calculations record of $CO_2e$ emissions from the turbines.

New Condition 6.2.22 requires notification of the initial startup of the combustion turbines following completion of the modifications to allow the combustion of fuel oil in the combustion turbines.

Section 7.0: Other Specific Requirements

Conditions 7.14.1 and 7.14.2 are added to require a timeline for construction and operation according to PSD requirements..

Attachment B Insignificant Activities Checklist, Insignificant Activities Based on Emission Levels and Generic Emission Groups

Attachment B was modified to include the new 2.5 million gallon vertical floating roof tank.

# APPENDIX A

## Draft Revised Title V Operating Permit Amendment
## Washington County Power
## Sandersville (Washington County), Georgia

# APPENDIX B

## Washington County PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. 547905, dated February 25, 2021
2. Additional Information Package Dated April 23, 2021

# APPENDIX C

## EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review

DMU Modeling Review Report – PSD
**Washington County Power, LLC**

## GENERAL INFORMATION

| | |
|---|---|
| Application # | 547905 |
| AIRS # | 30300039 |
| Applicant | Washington County Power, LLC |
| Application Date | 02/25/2021 |
| Preferred Report Deadline (30 days prior to "Draft Preliminary Determination Date") | 05/09/2021 |
| Draft Preliminary Determination Date | 06/09/2021 (Final) |
| Modeling Review Request Date | 03/17/2021 |
| Assigned SSPP PM1 | James Eason |
| Assigned Permit Engineer | Renee Browne |
| Date of Review Report Submission | 05/04/2021 |
| Assigned DMU Modeler | Susan Jenkins, Yunhee Kim, and Byeong-Uk Kim |
| Approved by DMU PM1 | 05/07/2021 |
| List of Reviewed Pollutants | CO, $PM_{10}$, $PM_{2.5}$, $NO_2$, and VOC |

### Review Summary

| | | |
|---|---|---|
| Are the modeled concentrations of all pollutants below SIL for Class I and Class II areas? | ☐ Yes | ☒ No |
| If "No" for the question above, list all pollutants whose modeled impacts were greater than or equal to the applicable SIL. | Class II 1-hour $NO_2$<br>Class II Annual $NO_2$<br>Class II 24-hour $PM_{2.5}$<br>Class II Annual $PM_{2.5}$ | |
| If cumulative modeling (i.e., Increment and NAAQS) is performed, are all pollutant below their applicable PSD Increment thresholds and NAAQS? | ☐ Yes | ☒ No |
| If "No" for the question above, list all pollutants whose modeled impacts were greater than applicable PSD Increment threshold and/or NAAQS. | Class II 1-hour $NO_2$ NAAQS (**Facility contribution is below SIL.**) | |
| Did the AQRV analysis show compliance? | ☒ Yes* | ☐ No |
| If "No" for the question above, list all AQRVs whose impacts were greater than thresholds. | | |

### Review Notes

DMU requested additional information to the application on May 4, 2021. As of May 7, DMU has not received requested information from the applicant yet. This report assumes no additional/updated modeling to be done. If new modeling files are submitted, DMU will update this report accordingly.

*DMU has received no comments made by FLM agencies as of May 7, 2021. The applicant submitted a concurrence letter from USDA Forest Service. However, that letter was for the applicant's AQRV analysis with an error. DMU advised the applicant to resubmit an updated AQRV analysis to FLMs and submit new concurrent letters to DMU.

## Modeling Results

All modeled concentrations are the applicant's final results unless otherwise noted.

**Table 1a. Class I Significant Impact Levels Modeling (Natural Gas Operation)**

| Pollutant | Averaging Period | Max Modeled Conc. ($\mu g/m^3$) | Secondary Impact ($\mu g/m^3$) | Total ($\mu g/m^3$) | SIL ($\mu g/m^3$) | Receptor UTM (Zone: 17) | |
|---|---|---|---|---|---|---|---|
| | | | | | | Easting (meter) | Northing (meter) |
| $NO_2$ | Annual | 0.0148 | N/A | 0.0148 | 0.1 | 364,896.6 | 3,657,852.3 |
| $PM_{2.5}$ | 24-Hour | 0.0156 | 0.00999 | 0.0256 | 0.27 | 299,642.2 | 3,615.722.7 |
| | Annual | 0.00976* | 0.000276 | 0.01004* | 0.05 | 364,896.6 | 3,657,852.3 |
| $PM_{10}$ | 24-Hour | 0.0152 | N/A | 0.0152 | 0.27 | 299,642.2 | 3,615,722.7 |
| | Annual | 0.00972 | N/A | 0.00972 | 0.05 | 364,896.6 | 3,657,852.3 |

*Recalculated with the applicant's modeling files submitted on April 23, 2021.

**Table 1b. Class I Significant Impact Levels Modeling (Fuel Oil Operation)**

| Pollutant | Averaging Period | Max Modeled Conc. ($\mu g/m^3$) | Secondary Impact ($\mu g/m^3$) | Total ($\mu g/m^3$) | SIL ($\mu g/m^3$) | Receptor UTM (Zone: 17) | |
|---|---|---|---|---|---|---|---|
| | | | | | | Easting (meter) | Northing (meter) |
| $NO_2$ | Annual | 0.0148 | N/A | 0.0148 | 0.1 | 364,896.6 | 3,657,852.3 |
| $PM_{2.5}$ | 24-Hour | 0.0315 | 0.00999 | 0.0415 | 0.27 | 299,642.2 | 3,615,722.7 |
| | Annual | 0.0108* | 0.000276 | 0.01111* | 0.05 | 364,397.4 | 3,654,387.0 |
| $PM_{10}$ | 24-Hour | 0.0311 | N/A | 0.0311 | 0.27 | 299,642.2 | 3,615,722.7 |
| | Annual | 0.0108 | N/A | 0.0108 | 0.05 | 364,397.4 | 3,657,387.0 |

*Recalculated with the applicant's modeling files submitted on April 23, 2021.

**Table 2a. Class II Variable Load Analysis Results for Simple Cycle Combustion Units**

| Pollutants | Averaging Period | 100% load ($\mu g/m^3$) | 75% load ($\mu g/m^3$) | 50% load ($\mu g/m^3$) | Is 100% load worst cases? |
|---|---|---|---|---|---|
| CO | 1-Hour | 19.19 | 16.50 | 12.19 | Yes |
| | 8-Hour | 7.64 | 6.34 | 4.64 | Yes |
| $NO_2$ | 1-Hour | 35.26 | 30.38 | 22.54 | Yes |
| | Annual | 0.0576 | 0.0540 | 0.0443 | Yes |
| $PM_{10}$ | 24-Hour | 0.93 | 0.78 | 0.64 | Yes |
| | Annual | 0.0493 | 0.0462 | 0.0378 | Yes |
| $PM_{2.5}$ | 24-Hour | 0.55 | 0.54 | 0.44 | Yes |
| | Annual | 0.0444 | 0.0429 | 0.0351 | Yes |

* DMU evaluated secondary $PM_{2.5}$ impacts were estimated with the MERP approach using the $NO_X$ and $SO_2$ emissions at the proposed facility.

**Table 2b. Class II Significant Impact Levels Modeling (Natural Gas)**

| Pollutant | Averaging Period | Max Modeled Conc. (μg/m$^3$) | Secondary Impact (μg/m$^3$)* | Total (μg/m$^3$) | SIL (μg/m$^3$) | SIA (km) | Receptor UTM Zone: 17 | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | Easting (meter) | Northing (meter) |
| CO | 1-hour | 106.45 | N/A | 106.45 | 2,000 | N/A | 315,123.0 | 3,663,140.6 |
| | 8-hour | 59.96 | N/A | 59.96 | 500 | N/A | 315,203.2 | 3,663,094.7 |
| $PM_{10}$ | 24-hour | 4.231 | N/A | 4.123 | 5 | N/A | 315,119.7 | 3,663,133.4 |
| | Annual | 0.24156 | N/A | 0.2145 | 1 | N/A | 315,203.2 | 3,663,094.7 |
| $NO_2$ | 1-hour | 100.0936 | N/A | **100.09** | 7.5 | 1.77 | 315,123.0 | 3,663,140.6 |
| | Annual | 2.51658 | N/A | **2.516** | 1 | 0.59 | 315,203.2 | 3,663,094.7 |
| $PM_{2.5}$ | 24-hour | 4.23149 | 0.185 | **4.416** | 1.2 | 0.36 | 315,119.7 | 3,663,133.4 |
| | Annual | 0.24156 | 0.0155 | **0.2570** | 0.2 | 0.36 | 315,203.2 | 3,663,094.7 |

**Table 2c. Class II Significant Impact Levels Modeling (Fuel Oil Operation)**

| Pollutant | Averaging Period | Max Modeled Conc. (μg/m$^3$) | Secondary Impact (μg/m$^3$)* | Total (μg/m$^3$) | SIL (μg/m$^3$) | SIA (km) | Receptor UTM Zone: 17 | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | Easting (meter) | Northing (meter) |
| CO | 1-hour | 106.45 | N/A | 106.45 | 2,000 | N/A | 315,123.0 | 3,663,140.0 |
| | 8-hour | 60.00039 | N/A | 60.00 | 500 | N/A | 315203.2 | 3,663,094.7 |
| $PM_{10}$ | 24-hour | 4.23254 | N/A | 4.232 | 5 | N/A | 315,119.7 | 3,663,133.4 |
| | Annual | 0.24417 | N/A | 0.2441 | 1 | N/A | 315,203.2 | 3,663,133.4 |
| $NO_2$ | 1-hour | 103.7601 | N/A | **103.76** | 7.5 | 53.64 | 315,189.4 | 3,662,942.4 |
| | Annual | 2.51658 | N/A | **2.516** | 1 | 0.59 | 315,203.2 | 3,663,094.7 |
| $PM_{2.5}$ | 24-hour | 4.23254 | 0.185 | **4.418** | 1.2 | 0.36 | 315,119.7 | 3,663,133.4 |
| | Annual | 0.24417 | 0.0155 | **0.2597** | 0.2 | 0.36 | 315,203.2 | 3,663,094.7 |

* DMU evaluated secondary $PM_{2.5}$ impacts were estimated with the MERP approach using the $NO_X$ and $SO_2$ emissions at the proposed facility.

**Table 3. Class II Increment Modeling**

| Pollutant | Averaging Period | Fuel Option* | Max Modeled Conc. (μg/m$^3$) | Secondary Impact (μg/m$^3$)*** | Total (μg/m$^3$) | Increment (μg/m$^3$) | Receptor UTM Zone: 17 | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | Easting (meter) | Northing (meter) |
| $NO_2$ | Annual | NG and FO | 4.08820 | N/A | 4.088 | 25.00 | 315,203.2 | 3,663,094.7 |
| $PM_{2.5}$** | 24-hour | NG | 6.65789 | 0.7118 | 7.37 | 9.00 | 315,083.3 | 3,663,296.3 |
| | Annual | NG | 0.95942 | 0.0628 | 1.02 | 4.00 | 315,225.9 | 3,663,084.1 |
| | 24-hour | FO | 6.66435 | 0.7118 | 7.38 | 9.00 | 315,083.3 | 3,663,296.3 |
| | Annual | FO | 0.96162 | 0.0628 | 1.02 | 4.00 | 315,225.9 | 3,663,084.1 |

* Fuel options: Natural Gas (NG) and Fuel Oil (FO).
** Highest concentration for annual averaging periods and second highest concentrations for 24-hour averaging periods.
*** DMU evaluated secondary $PM_{2.5}$ impacts with the MERP approach using the $NO_X$ and $SO_2$ emissions at the proposed facility and sources in the regional inventory.

**Table 4. $NO_2$ NAAQS Modeling**

| Pollutant | Averaging Period | Scenario | Fuel Option* | Max Modeled Conc. (µg/m³) | Background (µg/m³) | Total (µg/m³) | NAAQS (µg/m³) | Receptor UTM Zone: 17 | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Easting (meter) | Northing (meter) |
| $NO_2$ | 1-hour | 100% Load | NG | 66.902 | 30.3 | 97.202 | 188 | 315,234.9 | 3,662,889.9 |
| | | 4AM Startup | NG | 66.902 | 30.3 | 97.202 | 188 | 315,234.9 | 3,662,889.9 |
| | | 10AM Startup | NG | 66.902 | 30.3 | 97.202 | 188 | 315,234.9 | 3,662,889.9 |
| | | 100% Load | FO | 374.482 | 30.3 | **404.782** | 188 | 290,689.4 | 3,637,242.4 |
| | | 4AM Startup | FO | 374.482 | 30.3 | **404.782** | 188 | 290,689.4 | 3,637,242.4 |
| | | 10AM Startup | FO | 374.482 | 30.3 | **404.782** | 188 | 290,689.4 | 3,637,242.4 |
| | Annual | 100% Load | NG and FO | 4.088 | 4.5 | 8.588 | 100 | 315,203.2 | 3,663,094.7 |

* Fuel options: Natural Gas (NG) and Fuel Oil (FO).

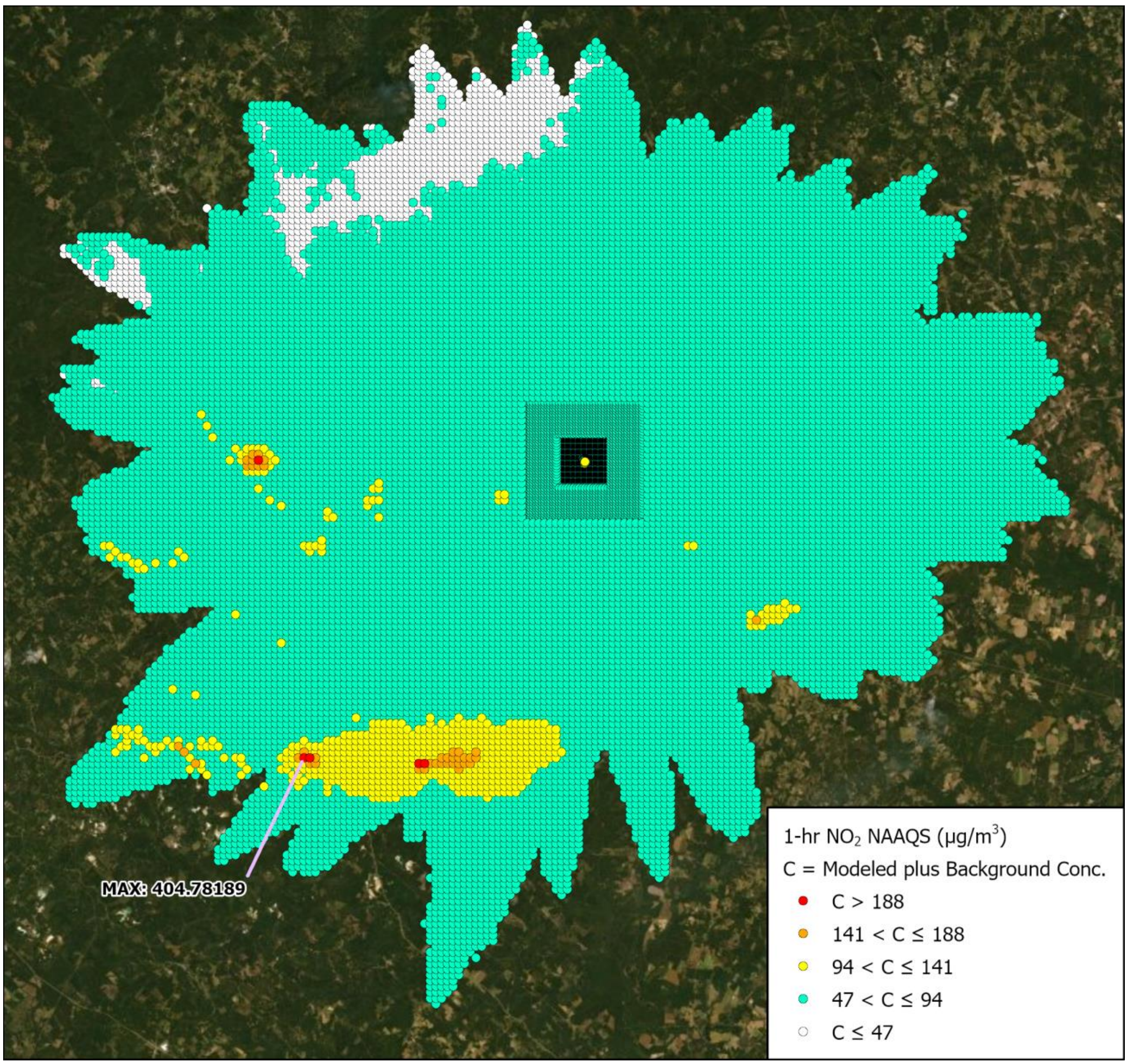


**Figure 1.** Spatial distribution of modeled $NO_2$ concentrations from 1-hour $NO_2$ NAAQS modeling (Fuel Oil Operation).

## Table 5. 1-hour $NO_2$ NAAQS Contribution Analysis (Fuel Oil Operation)

| Exceedance # | Rank | Scenario | All Modeled Conc. (µg/m³)* | WC Table 5. 1-hour $NO_2$ NAAQS Contribution Analysis (Fuel Oil Operation)P Modeled Conc. (µg/m³) | Receptor UTM (Zone: 17) | |
|---|---|---|---|---|---|---|
| | | | | | Easting (meter) | Northing (meter) |
| 1 | 8th | 100% Load | 374.48189 | 0.00142 | 290,689.4 | 3,637,242.4 |
| | | 4AM Startup | 374.48189 | 0.00142 | | |
| | | 10AM Startup | 374.48189 | 0.00142 | | |
| 2 | | 100% Load | 283.11218 | 0.00234 | 286,689.4 | 3,663,242.4 |
| | | 4AM Startup | 283.11218 | 0.00234 | | |
| | | 10AM Startup | 283.11218 | 0.00234 | | |
| 3 | | 100% Load | 196.31169 | 0.00184 | 301,189.4 | 3,636,742.4 |
| | | 4AM Startup | 196.31169 | 0.00184 | | |
| | | 10AM Startup | 196.31169 | 0.00184 | | |
| 4 | | 100% Load | 195.42920 | 0.00140 | 300,689.4 | 3,636,742.4 |
| | | 4AM Startup | 195.42922 | 0.00142 | | |
| | | 10AM Startup | 195.42920 | 0.00140 | | |
| 5 | | 100% Load | 171.58330 | 0.00162 | 291,189.4 | 3,637,242.4 |
| | | 4AM Startup | 171.58332 | 0.00165 | | |
| | | 10AM Startup | 171.58330 | 0.00162 | | |

* The cutoff threshold for a total 1-hour $NO_2$ impact is 157.7 (= 188 - 30.3) µg/m³ where 30.3 µg/m³ is background concentration. The exceedances occur from 8th rank to 82nd rank, but no exceedances afterwards. This refined modeling demonstrates that WCP will not cause or contribute a significant impact to the NAAQS exceedances at the 1-hour $NO_2$ averaging period.

**Table 6. $PM_{2.5}$ NAAQS Modeling**

| Pollutant | Averaging Period | Fuel Option* | Max Modeled Conc. (µg/m³)** | Secondary Impact (µg/m³)*** | Background (µg/m³) | Total (µg/m³) | NAAQS (µg/m³) | Receptor UTM (Zone: 17) | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Easting (meter) | Northing (meter) |
| $PM_{2.5}$ | 24-hour | NG | 4.46937 | 0.204034 | 18.4 | 23.0734 | 35 | 315,072.8 | 3,663,273.6 |
| | Annual | NG | 0.89233 | 0.0171376 | 7.9 | 8.80947 | 12 | 315,203.2 | 3,663,094.7 |
| | 24-hour | FO | 4.47351 | 0.204034 | 18.4 | 23.0775 | 35 | 315,072.8 | 3,663,273.6 |
| | Annual | FO | 0.89450 | 0.0171376 | 7.9 | 8.8116 | 12 | 315,203.2 | 3,663,094.7 |

* Fuel options: Natural Gas (NG) and Fuel Oil (FO).
** Highest concentration for annual averaging periods and 8th highest concentrations for 24-hour averaging periods.
*** DMU evaluated secondary $PM_{2.5}$ impacts with the MERP approach using the $NO_X$ and $SO_2$ emissions at the proposed facility.

**Table 7. Additional Analysis**

| Analysis | Results |
|---|---|
| Ozone Impact | The cumulative ozone value is less than the NAAQS limit for ozone. |
| Significant Monitoring Concentration | No preconstruction monitoring is required for 8-hour CO, Annual $NO_2$, and 24-hour $PM_{10}$. |
| AQRV* | No adverse comments from the applicable FLMs. |
| Others | Class II Visibility Analysis – Showed no issues based on impact evaluation (Tables 9a-9d).<br>Soils and Vegetation Analysis – No detrimental effects.<br>Economic Growth – No detrimental effects. |

*DMU has received no comments made by FLM agencies as of May 7, 2021. The applicant submitted a concurrence letter from USDA Forest Service. However, that letter was for the applicant's AQRV analysis with an error. DMU advised the applicant to resubmit an updated AQRV analysis to FLMs and submit new concurrent letters to D

**Table 8a. Level 2 VISCREEN Results-Sandersville/Kaolin Airport**

| Background | Theta | Azi | Distance | Alpha | Delta E | | Contrast | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Crit | Plume | Crit | Plume |
| SKY | 10 | 122 | 21 | 46 | 2.0 | 0.734 | 0.05 | -0.001 |
| | 140 | 122 | 21 | 46 | 2.0 | 0.247 | 0.05 | -0.004 |
| TERRAIN | 10 | 84 | 18 | 84 | 2.0 | 0.246 | 0.05 | 0.003 |
| | 140 | 84 | 18 | 84 | 2.0 | 0.071 | 0.05 | 0.002 |

**Table 8b. Level 2 VISCREEN Results-Hamburg State Park**

| Background | Theta | Azi | Distance | Alpha | Delta E | | Contrast | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Crit | Plume | Crit | Plume |
| SKY | 10 | 84 | 20.5 | 84 | 2.0 | 0.272 | 0.05 | 0.000 |
| | 140 | 84 | 20.5 | 84 | 2.0 | 0.093 | 0.05 | -0.001 |
| TERRAIN | 10 | 84 | 20.5 | 84 | 2.0 | 0.079 | 0.05 | 0.001 |
| | 140 | 84 | 20.5 | 84 | 2.0 | 0.023 | 0.05 | 0.001 |

**Table 8c. Level 2 VISCREEN Results-Baldwin State Forest**

| Background | Theta | Azi | Distance | Alpha | Delta E | | Contrast | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Crit | Plume | Crit | Plume |
| SKY | 10 | 118 | 24.5 | 51 | 2.0 | 0.746 | 0.05 | -0.001 |
| | 140 | 118 | 24.5 | 51 | 2.0 | 0.250 | 0.05 | -0.004 |
| TERRAIN | 10 | 84 | 21.5 | 84 | 2.0 | 0.226 | 0.05 | 0.003 |
| | 140 | 84 | 21.5 | 84 | 2.0 | 0.067 | 0.05 | 0.002 |

**Table 8d. Level 2 VISCREEN Results-Baldwin County Airport**

| Background | Theta | Azi | Distance | Alpha | Delta E | | Contrast | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Crit | Plume | Crit | Plume |
| SKY | 10 | 84 | 24 | 84 | 2.0 | 0.088 | 0.05 | 0.000 |
| | 140 | 84 | 24 | 84 | 2.0 | 0.030 | 0.05 | 0.000 |
| TERRAIN | 10 | 84 | 24 | 84 | 2.0 | 0.022 | 0.05 | 0.000 |
| | 140 | 84 | 24 | 84 | 2.0 | 0.007 | 0.05 | 0.000 |

# DMU Modeling Review Report – TAP
# Washington County Power, LLC

## GENERAL INFORMATION

| | |
|---|---|
| Application# | 547905 |
| AIRS # | 30300039 |
| Applicant | Washington County Power, LLC |
| Application Date | 02/25/2021 |
| Preferred Report Deadline (15 days prior to "Draft Permit Date") | 05/26/2021 |
| Draft Permit Date | 06/09/2021 |
| Modeling Review Request Date | 03/17/2021 |
| Assigned SSPP PM1 | James Eason |
| Assigned Permit Engineer | Renee Browne |
| Date of Review Report Submission | 05/04/2021 |
| Assigned DMU Modeler | Susan Jenkins |
| Approved by DMU PM1 | 05/07/2021 |

| | |
|---|---|
| List of Reviewed Pollutants | Acrolein, Arsenic, Benzene, Beryllium, 1,3-Butadiene, Cadmium, Formaldehyde, Lead, Manganese, Selenium, and Sulfuric Acid |

## Review Summary

| | | |
|---|---|---|
| Maximum Ground Level Concentrations (MGLCs) of all TAPs below Acceptable Ambient Concentrations (AACs)? | ☒ Yes | ☐ No |

## Modeling Results

**Table 1. TAP MGLC Assessment**

| TAP | Averaging Period | AAC (µg/m$^3$) | Max Modeled Conc. (µg/m$^3$) | Receptor UTM Zone: | |
|---|---|---|---|---|---|
| | | | | Easting (meter) | Northing (meter) |
| Acrolein | Annual | 0.02 | 0.00002 | 315,342.0 | 3,663,223.2 |
| | 15-Minute | 23 | 0.00372 | 312,444.3 | 3,662,591.0 |
| Arsenic | Annual | 0.000233 | 0.00004 | 315,352.4 | 3,663245.9 |
| | 15-Minute | 0.2 | 0.00688 | 312,444.3 | 3,662,591.1 |
| Benzene | Annual | 0.13 | 0.0111 | 315,044.3 | 3,663,391.1 |
| | 15-Minute | 1600 | 0.245 | 315,044.3 | 3,663,391.1 |
| Beryllium | 15-Minute | 0.5 | 0.000198 | 312,444.3 | 3,662,591.1 |
| | Annual | 0.004 | <1.00E-05 | 315,325.4 | 3,663,245.9 |
| 1,3-Butadiene | Annual | 0.03 | 0.00005 | 315,352.4 | 3,663,245.0 |
| | 15-Minute | 1100 | 0.01 | 312,444.3 | 3,662,591.1 |
| Cadmium | Annual | 0.00556 | 0.00004 | 315,203.2 | 3,663,094.7 |
| | 15-Minute | 30 | 0.00301 | 312,444.3 | 3,662,591.1 |
| Formaldehyde | 15-Minute | 245 | 0.416 | 312,444.3 | 3,662,591.1 |
| | Annual | 1.1 | 0.00381 | 315,362.8 | 3,663,268.7 |
| Lead | 24-Hour | 0.00092 | 0.00092 | 313,644.3 | 3,658,691.1 |
| Manganese | Annual | 0.05 | 0.00275 | 315,352.4 | 3,663,245.9 |
| | 15-Minute | 500 | 0.493 | 312,444.3 | 3,662,591.1 |
| Selenium | 24-Hour | 0.48 | 0.00164 | 313,644.3 | 3,658,691.1 |
| Sulfuric Acid | 24-Hour | 2.4 | 0.18 | 315,119.70 | 3,663,133.4 |
| | 15-Minute | 300 | 0.57 | 315,123.00 | 3,663,140.6 |